DR. 1015

ANL-79-62 ANL-79-62

CONF-790855-- CONF-790855--

185
4-8-80

MASTER

THE PROCEEDINGS OF THE 1979 SYMPOSIUM ON INSTRUMENTATION AND CONTROL FOR FOSSIL ENERGY PROCESSES

August 20-22, 1979

Denver Marriott
Denver, Colorado

U of C-AUA-USDOE

ARGONNE NATIONAL LABORATORY, ARGONNE, ILLINOIS

Prepared for the U. S. DEPARTMENT OF ENERGY
under Contract W-31-109-Eng-38

The facilities of Argonne National Laboratory are owned by the United States Government. Under the terms of a contract (W-31-109-Eng-38) among the U. S. Department of Energy, Argonne Universities Association and The University of Chicago, the University employs the staff and operates the Laboratory in accordance with policies and programs formulated, approved and reviewed by the Association.

MEMBERS OF ARGONNE UNIVERSITIES ASSOCIATION

The University of Arizona
Carnegie-Mellon University
Case Western Reserve University
The University of Chicago
University of Cincinnati
Illinois Institute of Technology
University of Illinois
Indiana University
The University of Iowa
Iowa State University
The University of Kansas
Kansas State University
Loyola University of Chicago
Marquette University
The University of Michigan
Michigan State University
University of Minnesota
University of Missouri
Northwestern University
University of Notre Dame
The Ohio State University
Ohio University
The Pennsylvania State University
Purdue University
Saint Louis University
Southern Illinois University
The University of Texas at Austin
Washington University
Wayne State University
The University of Wisconsin-Madison

NOTICE

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government or any agency thereof, nor any of their employees, make any warranty, express or implied, or assume any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represent that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, mark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Printed in the United States of America
Available from
National Technical Information Service
U. S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

NTIS price codes
Printed copy: A23
Microfiche copy: A01

ANL-79-62
CONF-790855

Distribution Category:
Coal Conversion Demonstration
Plants (UC-89)

ARGONNE NATIONAL LABORATORY
9700 South Cass Avenue
Argonne, Illinois 60439

THE PROCEEDINGS OF THE 1979 SYMPOSIUM ON INSTRUMENTATION AND CONTROL FOR FOSSIL ENERGY PROCESSES

August 20-22, 1979
Denver Marriott
Denver, Colorado

Sponsored by

Argonne National Laboratory

U. S. Department of Energy
Office of Fossil Energy

Prepared for the United States Department of Energy
under ANL 189a - 49622

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

ACKNOWLEDGEMENTS

The Department of Energy - Fossil Energy and Argonne National Laboratory, sponsors of the 1979 Symposium on Instrumentation and Control for Fossil Energy Processes, thank the 1979 Symposium Committee for organizing and presenting this Symposium. The Symposium Committee members, listed on the following page, acknowledge the many persons who contributed to the success of the Symposium: speakers presenting papers, luncheon and banquet speakers, session chairpersons, organizations participating in the Show and Tell hardware display, and the dedicated behind-the-scenes workers.

Special recognition and thanks are due Richard Green of Trade Associates for presenting the commercial instrumentation exposition concurrent with the Symposium.

Funding of this Symposium by the Department of Energy - Fossil Energy and the continued support by Hershul T. Jones, Assistant Director of Initial Plant Operations/Materials and Component Development, are gratefully acknowledged.

The many organizations, including private industry, universities, national laboratories, and government are thanked for the numerous contributions by their employees. Their investment of time and effort led to a successful Symposium, furthering the solution of instrumentation and control problems in fossil energy processes.

The 1980 Symposium Committee is planning the 1980 Symposium for Virginia Beach, Virginia, June 9-11.

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

SYMPOSIUM COMMITTEE

GENERAL CHAIRMAN:

W. W. Managan, Argonne National Laboratory

PAST GENERAL CHAIRPERSON:

N. M. O'Fallon, Argonne National Laboratory

DOE SPONSOR LIAISON:

T. K. Lau, DOE Division of Fossil Fuel Processing

PROGRAM CHAIRPERSON:

J. V. Walsh, Jet Propulsion Laboratory

VICE PROGRAM CHAIRPERSON:

W. R. Miller, Stearns-Roger, Inc.

HARDWARE DISPLAY CHAIRPERSON:

R. W. Doering, Argonne National Laboratory

CONFERENCE ARRANGEMENTS:

M. L. Holden, Argonne National Laboratory

SECRETARY:

R. W. Doering, Argonne National Laboratory

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

TABLE OF CONTENTS

TABLE OF CONTENTS (Contd.)

Page

Master of Ceremonies for Tuesday
T. K. Lau *(U. S. Department of Energy)*

Session A — Flow Instrumentation and Control

Session Chairman: **D. Hartley** *(Sandia Laboratories)*

Session B — Analysis and Sampling

Session Chairman: **Raj Shah** *(Rockwell International)*

Master of Ceremonies for Luncheon
W. W. Managan *(Argonne National Laboratory)*

Session Chairman: **E. A. Lloyd** *(Department of Energy)*

Show and Tell — A Hardware Display

Chairman: **R. W. Doering** *(Argonne National Laboratory)*

OVERVIEW OF DOE FOSSIL ENERGY PROGRAMS AND PLANS

E. A. Lloyd, Manager
Process & Program Management
Fossil Fuel Processing Division
Department of Energy
Washington, D. C. 20545

It is a pleasure and an honor to be here today. I want to share an overview of DOE fossil energy programs and planning, with special attention to the conversion of coal into synthetic fuels. It's perhaps an understatement to say that synthetic fuels have captured the imagination of many citizens since the President's proposals in mid-July. I will focus on the DOE major synthetic fuel projects for which I am responsible but I will touch on other aspects of the fossil energy program that can benefit from the development of better instrumentation and controls.

The President's energy program proposes a broad range of initiatives to reduce oil imports by 4.5 million barrels per day, by 1990 (Figure 1). Of this total, approximately 1.5 to 2 million barrels would be produced through development of synthetic fuels.

To achieve this goal, two new institutional mechanisms are proposed. The first is the establishment of the Energy Security Corporation to coordinate and finance development of synfuels, primarily through revenues from a windfall profits tax. Second, the President has proposed the establishment of an Energy Mobilization Board to insure that critical energy facilities do not get bogged down in Federal, State and local permitting. This Board does not change current environmental and other regulations but seeks to minimize the time required.

There should be a clear understanding that our energy future rests in the hands of competitive American industry - the Government is not going to build the huge commercial facilities required. Neither does our energy future lie with any one source. Coal, shale oil, enhanced recovery of natural gas and oil, solar and nuclear will all have roles to play in our energy supply mix. In short, there are no panaceas, and we face a critical decade of government - industry cooperation before these technologies can be commercialized to produce significant amounts of energy from U. S. domestic resources.

I'd like to discuss the slate of technologies in the fossil energy programs, briefly reviewing the status of major projects to help us focus on the role and importance of instrumentation and control in the design of these plants.

The fossil energy budget is divided into three major programs - - direct use of coal and magnetohydrodynamics; extraction; and synfuels (Figure 2). In this discussion, emphasis first will be placed upon those technologies for converting coal into synthetic liquids and gases - - techniques that industry either has today or will soon have as we move into the 1980's.

This synfuels program represents about 42 percent of the fossil energy budget. Funding is split roughly in half between gasification and liquefaction, with a smaller component for advanced research (Figure 3).

Synthetic fuel technologies - - either gasification or liquefaction - - have a common thread. One ton of coal is equivalent to one and a half to three barrels of crude oil, depending on the efficiency of the process.

We have made considerable progress, particularly in the last few years. Our program has resulted in the construction and operation of several pilot plants to test - - at an intermediate scale - - advances in coal conversion processes - - such as the IGT HyGas pilot plant which has been under test in Chicago for almost five years (Figures 4 and 5).

The gas industry has been a prime partner in the construction and operation of many of these plants.

We now believe we are ready to move to the next step - - the demonstration plant; as shown in an artist's drawing of the Conoco High Btu Project (Figure 6). A demonstration plant will be the last step before construction of a commercial production plant. It will operate using components of commercial or near-commercial scale.

We are supporting two competitive designs of a demonstration plant that will produce pipeline-quality high BTU gas - - one by Conoco Coal Development Company, a subsidiary of Conoco, Inc. and the other by the Illinois Coal Gasification Group, a consortium of 5 Illinois gas utilities (Figure 7).

And we have two contractors designing large demonstration plants to produce medium BTU, or synthesis gas - W. R. Grace of New York, and a municipal utility in Memphis, Tennessee.

Next year, we will be in a position to determine the technical, economic and environmental feasibility of these designs, and whether to proceed with final design and construction of the plants. On our current schedule, we will have the first demonstration plant operating in 1982 or 1983, and follow-on commercial plants at the same sites may be possible as early as 1985 or 86.

To review the coal conversion process in an elementary way, we can make gas from coal (Figure 8). The two High Btu projects use technologies that produce methane from synthesis gas; the Grace and Memphis projects are designed to produce medium BTU or synthesis gas. All four of these plants could be modified to produce methanol (Figure 9).

This is called "indirect liquefaction" - - synthesis gas can be chemically recombined to form a variety of liquids. The first commercial liquids-from-coal plants will probably use the indirect method, which is basically commercial and bears minimal risk.

To recombine synthesis gas to form methanol is relatively easy; we've been doing that for years using natural gas as the chief feedstock.

Methanol can be used directly - - in turbines, for example, or it can be added to gasoline, much as ethanol is used today in gasahol. Or again, it can be converted directly to high octane gasoline.

This last step has been developed under DOE's program with the Mobil Oil Corporation and appears to be an extremely promising option for use in commercial plants - - construction of which could start within the next few years.

The Lurgi/Fischer-Tropsch direct liquefaction process provided liquids for the Germans in World War II and has been in commercial production for over 20 years in South Africa. It will work on some Western U. S. coals, but the vast Eastern coal resource - near our industrial heartland - is not suitable for the Lurgi/Fischer-Tropsch process.

Therefore, our research and development program has focused on liquefaction techniques that are suitable for Eastern coals. These processes add hydrogen directly to the coal and convert it into a liquid (Figure 10).

The Germans also used this technique in their production of synthetic liquid fuel in World War II. Yet, the processes they used were bulky, troublesome to operate, and considerably out of today's economic ballpark.

In developing the direct liquefaction processes, we have made significant strides.

Today, four new liquefaction technologies are nearing demonstration of commercial potential for the late 1980's (Figure 11).

Working with the Exxon Company, we are constructing a large Exxon Donor Solvent Plant outside of Baytown, Texas (Figure 12). It will process over 200 tons of coal per day - - converting each ton into 2.5 or 3 barrels of oil. The plant should go into operation by the middle of next year. Figure 12 shows the status of construction as of February 1979.

Also, we are in the final stages of construction of a second very large pilot plant in Catlettsburg, Kentucky (Figure 13). Depending on how we run the operation, this H-Coal Plant could process from 200 to 600 tons of coal each day. This project is sponsored by Ashland Oil, Hydrocarbon Research, and others.

Like the Exxon Plant, the Kentucky Plant could go into initial operation next year. While these facilities are classified as pilots, they are large enough so that when we achieve satisfactory operation - - and with the scale up experience of the SRC demonstration plants - - we believe these processes can be scaled directly to commercial size facilities, leapfrogging the demonstration plant stage.

Two of the direct liquefaction technologies evolved from the same root - - the solvent-refined-coal process which has been developed at government expense over the past 15 years (Figure 14). We've come to the point where a 50-ton per day pilot plant at Fort Lewis, Washington (Figure 15) has operated for over four years and a small plant in Wilsonville, Alabama, for almost five.

And, as in gasification, we have taken the next step.

Slightly over a year ago, we signed contracts to begin the design of commercial-scale modules of the SRC process - - as shown in an artist's concept (Figure 16).

Southern Company Services, along with Air Products and Wheelabrator-Frye, their industrial partners - - is designing a variation of the process that produces a clean-burning solid fuel, SRC I. The Gulf Oil Corporation is designing an SRC II plant to produce a liquid fuel.

Construction of one or both of these plants would begin in 1981 - - near Morgantown, West Virginia, for the Gulf Plant; or near Owensboro, Kentucky, for the solid version. Operation could begin as soon as late 1983 or early 1984.

These demonstration plant sites are suitable for commercial production plants that would have the capacity of as many as five of these first modules. A single module will process 6,000 tons of coal each day, producing the equivalent of 20,000 barrels of oil. A commercial facility would process 30,000 tons of coal, producing the equivalent of 100,000 barrels of oil per day.

Thus, with EDS, H-Coal and the two SRC Projects, four direct liquefaction processes have reached a major scale of development (Figure 17).

Together with the currently commercial Lurgi and the four near term gasification processes that could produce synthesis gas for indirect synthetic liquid production, these four direct liquefaction facilities will be ready for widespread commercialization in the late 1980's or early 90's.

Thus far, we have reviewed the status of the major gasification and liquefaction synfuels projects. The fossil energy programs also include direct combustion, underground coal conversion, oil from shale, and magnetohydrodynamics.

The demand for coal in 1985 is projected to range from 1 to 1.2 billion tons. Most of the coal consumed in this country is and will continue to be burned directly. Any program to increase coal utilization must place primary emphasis on promoting direct coal combustion.

A technology for using the country's vast supply of coal to produce energy by direct combustion is the fluidized-bed process. Atmospheric fluidized-bed combustion will play a major role in utility applications because of its simplicity and economics. We have such a project underway in Rivesville, West Virginia (Figure 18).

In underground coal conversion, development of an in-situ gasification process for bituminous coal is important (Figure 19). This process can use resources located within or near regions of high population density and energy use. Primary objectives include demonstration of a reliable method of igniting bituminous coal at depth, and evaluating the need for surface and sub-surface instrumentation and process equipment for effective process control. Instrument design work is in progress and development of the underground coal conversion process is encouraging.

Next to coal, oil shale is the nation's largest fossil fuel resource (Figure 20). Available technology shows promise of being competitive. Either underground or surface mining can be used, depending on the extent and richness of the formation. Vast deposits in Colorado-Wyoming-Utah could provide up to 700 billion barrels of recoverable oil (Figure 21). Two tons of shale - about the volume of an office desk - would yield more than a barrel of oil. Large, lower-grade formations exist in the Eastern U. S.

As an incentive to stimulate private industry production, the Administration has proposed a $3.00 tax credit for each barrel of oil produced from shale. This could provide 300,000 barrels a day in the 1990's, with initial commercial implementation by 1985. Four major in-situ government/industry cost-sharing contracts, plus other research and development projects, are in progress.

In the Eastern Gas Shales, there are hundreds of trillions of cubic feet of natural gas. Currently, there exists no accurate estimate of gas in place, nor can we predict what fraction of the gas can be recovered.

Once the zones of highest potential are identified, the problem of maximum recovery still remains. Natural or induced fracturing of the shale reservoir is important for obtaining commercial gas flows (Figure 22). Laboratory studies are currently in progress to identify which fracturing methods are the most effective.

Magnetohydrodynamics (or MHD for short) can be a future source of low-cost, central station, electric power. MHD power generation is based on the direct conversion of heat to electricity by passing a high-temperature, high velocity, electrically conducting gas through a magnetic field (Figure 23). We have a cooperative program underway with the Soviets: They have a natural gas-MHD plant on line. We are interested in using coal in an MHD plant.

The program utilizes facilities in 15 States, with two government test facilities located in Tullahoma, Tennessee, and Butte, Montana. Progress is exceeding expectations.

Long-term inexhaustible Central Power Generation technologies, such as nuclear fusion and breeder reactors, will not be in widespread commercial use until well after the turn of the century.

With an estimated 17 hundred billion tons of proven domestic coal reserves, as shown on the map (Figure 24), and another 23 hundred billion tons that may lie undiscovered, there are ample coal resources. It is our job to develop economical and environmentally acceptable extraction, direct combustion, gasification and liquefaction technologies to reduce our dependence on imported oil. But regardless of the process for utilizing our coal resources, future commercial plants for the conversion of coal to more acceptable forms of energy will be expensive. For example, to achieve the goal of displacing two million barrels of imported oil will require massive financial commitments by either government or private companies, or both. To get that amount of fuel from gasification or liquefaction technology will require twenty plants costing $40 billion and each producing 100,000 barrels a day. Massive funding and many massive physical plants will be necessary to achieve our national goals. Also, mass production facilities must be built to produce the equipment needed: for the new mines that must be opened, for the plants, and to get the product to the markets. Development of adequate instruments and controls is an essential part of the eventual successful commercial production of synthetic fuels. New instruments and control devices are required to control these new processes, assure safe operation of new plants, and achieve economic "on stream" times.

Costs are high, but the cost of not making these investments could be higher still through our vulnerability to foreign sources of supply. The major determinant of the competitiveness of most new technologies will be the world price of oil. Plants will cost billions, and the capital investment in these plants is the major factor in the cost of the synthetic fuels they produce. If the price of oil continues to rise at the pace of the past few years, there will soon be a cost cross-over that will make the economics of building commercial sized plants attractive to private industry. The cost of imported oil on the spot market in recent weeks has already exceeded our estimate of the equivalent value of synthetic fuels.

Most private sector experts agree that the impetus for commercialization will have to come from the Federal Government. The Federal synthetics program received a healthy boost when the White House endorsed a congressional plan to have the Federal Government buy a considerable amount of synthetic fuels. Current administration and congressional proposals are encouraging.

I would like to make this key point: despite the recent flurry of synfuel-related action, we are not plunging into untested waters. This map (Figure 25) summarizes our major on-going projects and I think it shows that there is hardware operating, being built or being designed - - only some of which I have described.

Moreover, private industry is an integral part of these efforts - - and this is essential. Our eight largest projects - four gasification demonstrations (two high BTU and two medium BTU), and four liquefaction (two SRC, EDS and H-Coal), are sponsored and will be significantly financed by eight different U. S. firms. A number of other private enterprises are involved in other projects. Only by initiating and encouraging competition between these and other private firms can we hope to meet the synfuel production goals.

Private industry is the ultimate customer for the technologies that emerge from these programs. U. S. companies must be encouraged to finance, build and operate many, big commercial coal conversion plants, based on the technologies they understand and those techniques that best suit their needs and markets.

If private industry can convert or utilize coal in acceptably clean and economic processes, our dependence on foreign oil can be significantly reduced.

Likewise, the full support of those who understand the importance of instrumentation and control is vital in attaining these goals. Manpower and manufacturing capability to develop and supply the instrumentation and control equipment is a great challenge. All components and instrumentation in the early demonstration plants will be such that subsequent expansion to commercial production can be expedited. The demonstration plants will have limited capacity with full-scale commercial equipment and instrumentation that can be expanded readily or replicated to produce a commercial plant of any desired size.

Timing priorities demand that wherever possible, "off-the-shelf" hardware must be used instead of waiting for further development. We must act now to employ the best available technology in achieving commercial operation. We will continue an aggressive development program for future improvement in technology: certainly including instrumentation and control as vital concerns. We intend to seek the counsel of industry partner representatives and technical experts to identify and define the most urgent instrumentation and control requirements and to guide the instrumentation and control program funded by the DOE Fossil Fuel Processing Division. Your own program plans, providing for specific instrumentation and control needs, will be described fully in other presentations at this meeting.

Together, we must look outward at the broader issues and needs, rather than looking inward at our individual problems and individual contributions. No difficulty - - such as manufacturing production capability, instrumentation and control, or government regulations - - can be permitted to become show stoppers. We must proceed with the tools at hand to demonstrate the practicality of synfuel production while simultaneously and urgently developing the hardware, and particularly the instruments and control equipment that will be required to effectively operate the big commercial plants.

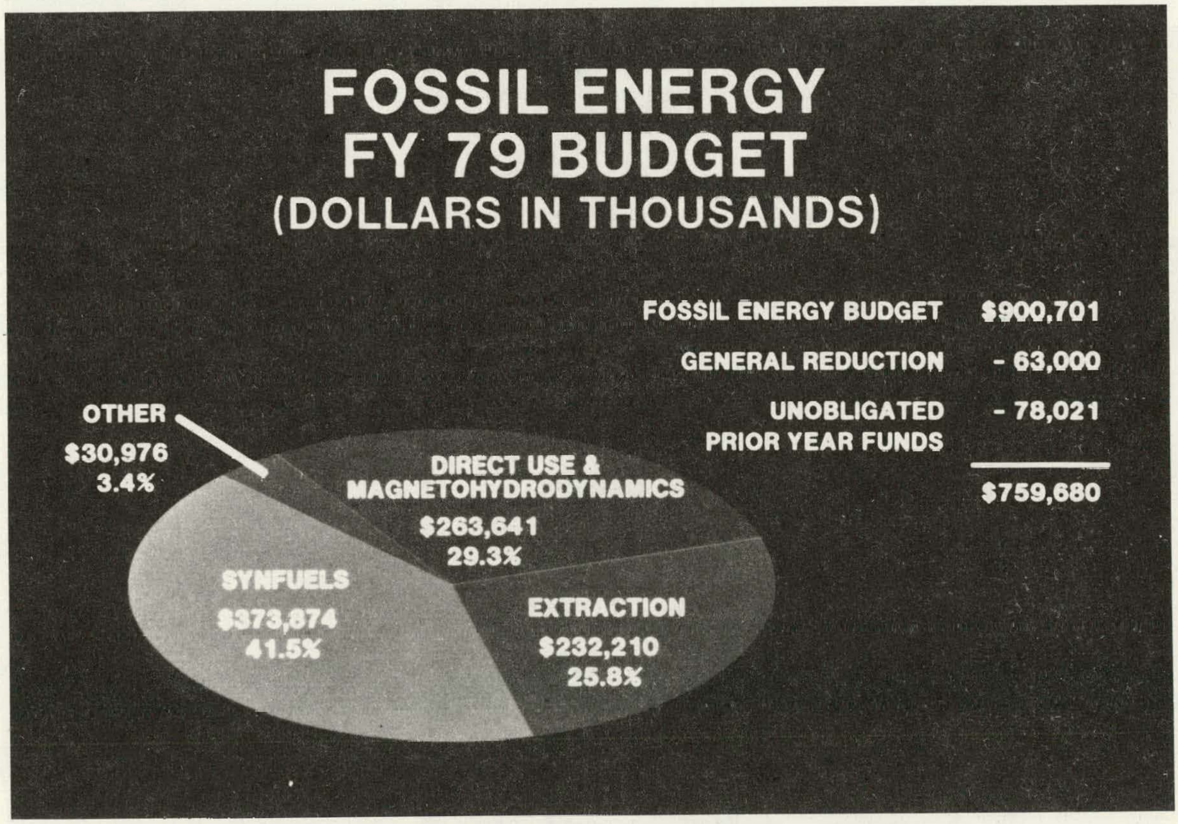
With cooperative participation of all segments of American private industry and the government, a synthetic fuels industry can develop quickly enough to meet the national requirement. With this participation, synthetic fuels will take us a vital step away from our over-reliance on foreign oil.

By dealing pragmatically with current "real world" problems, industry and government working together will succeed in our commitment to become, once again, independent of foreign control of our destiny.

PRESIDENT'S ENERGY PROGRAM

	BBL/D
UTILITIES—CONVERT FROM OIL	750,000
HEAVY CRUDE OIL	500,000
CONSERVATION	500,000
MASS TRANSIT, BETTER AUTO EFFICIENCY	250,000
"UNCONVENTIONAL" NATURAL GAS	500,000—1,000,000
SOLAR	—
SUB-TOTAL	2,500,000—3,000,000
SYN FUELS FROM COAL SHALE OIL METHANOL, ETHANOL	2,000,000—1,500,000
TOTAL	4,500,000

Figure 1



FOSSIL ENERGY
FY 79 BUDGET
(DOLLARS IN THOUSANDS)

FOSSIL ENERGY BUDGET	$900,701
GENERAL REDUCTION	- 63,000
UNOBLIGATED PRIOR YEAR FUNDS	- 78,021
	$759,680

Figure 2

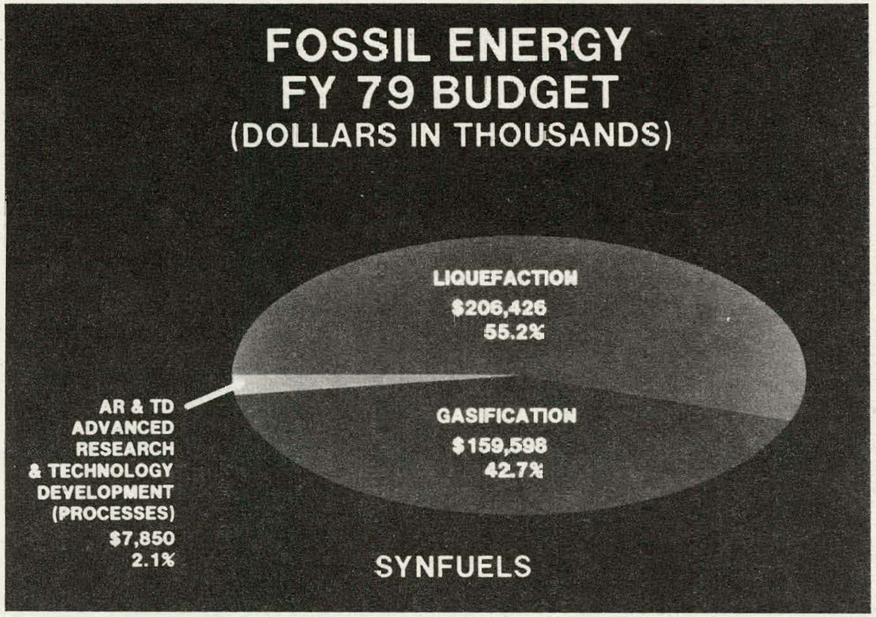


Figure 3

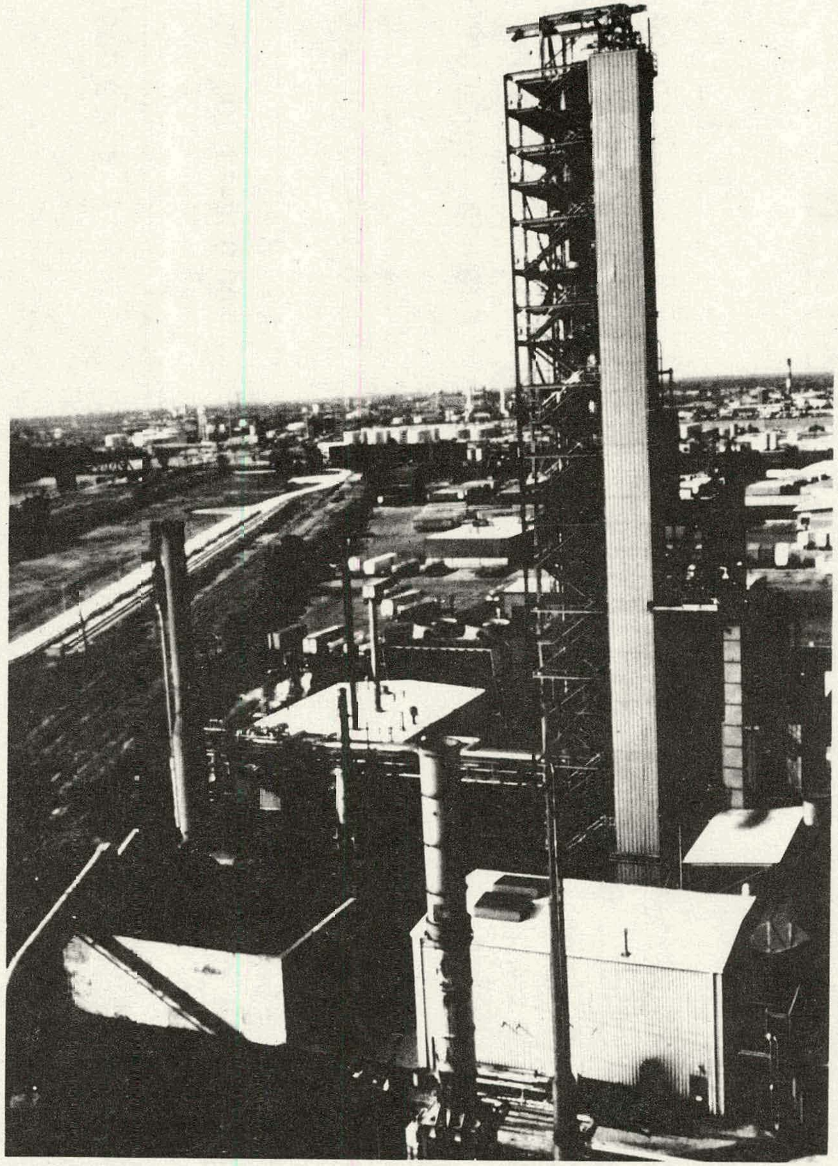


Figure 4 - IGT Gasification Pilot Plant
at Chicago, Illinois

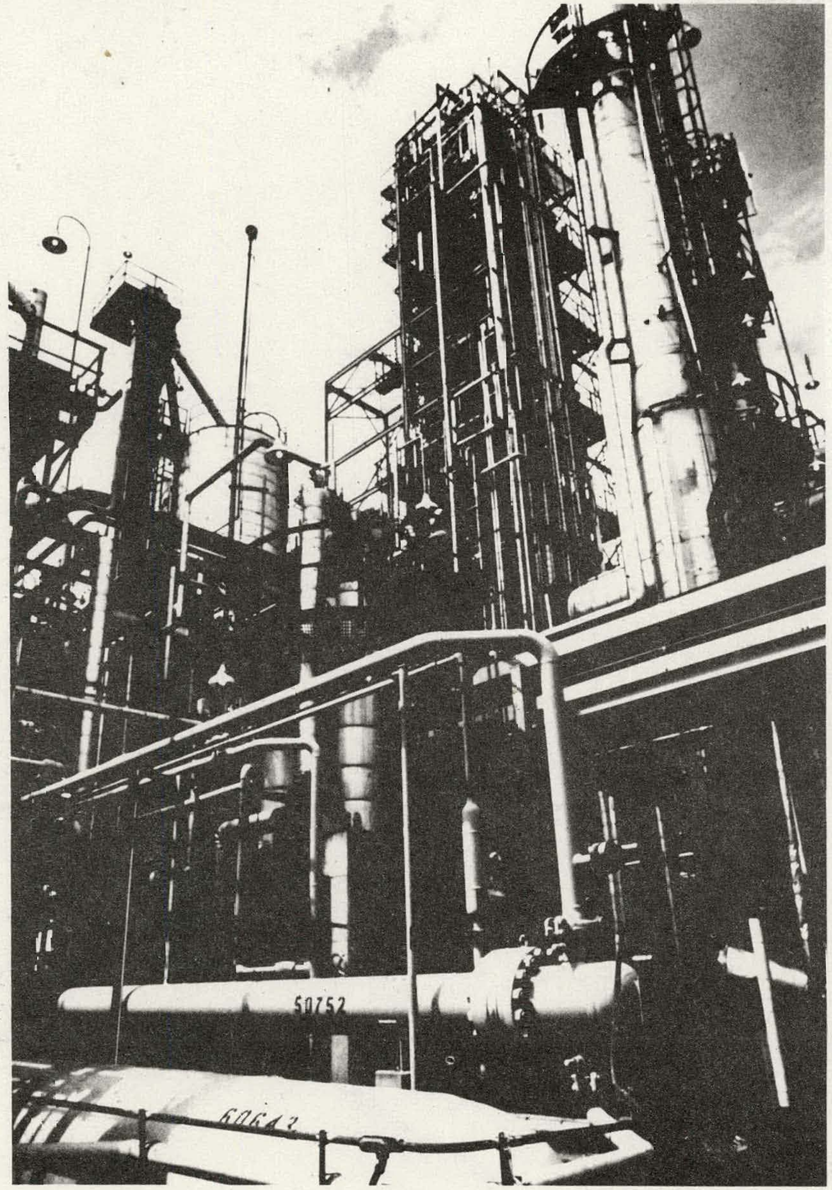


Figure 5 - HyGas Pilot Plant at
Chicago, Illinois

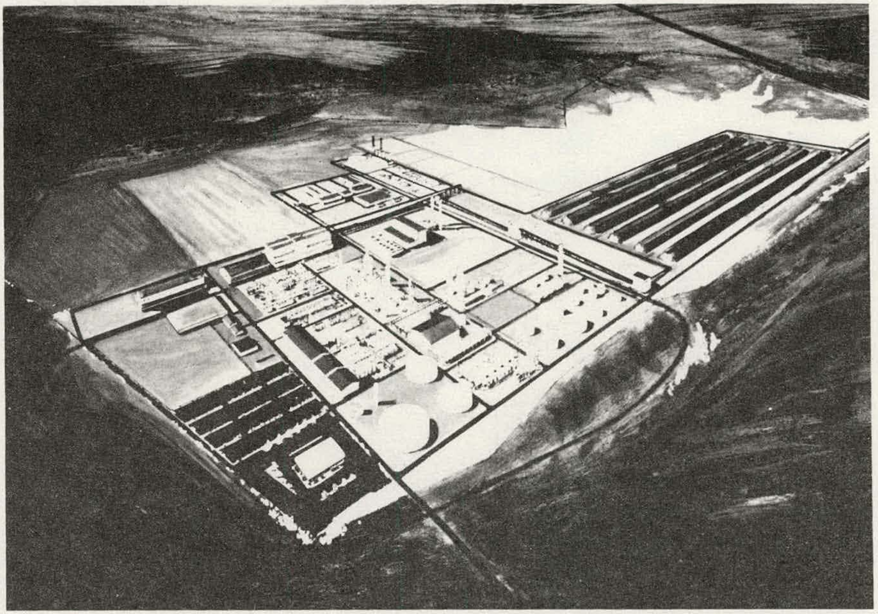


Figure 6 - Artist's Drawing, Conoco
High Btu Demonstration Plant

MAJOR GASIFICATION PROJECTS

PRODUCT	SPONSOR	SITE	EARLIEST PRODUCTION DEMO	 1st COMMERCIAL
PIPELINE GAS	CONOCO	NOBLE COUNTY OHIO	1983	1986
PIPELINE GAS	ILLINOIS COAL GASIFICATION GP	PERRY COUNTY ILLINOIS	1983	1985
MED BTU SYNTHESIS GAS	W.R. GRACE	BASKETT KENTUCKY	1982	1985
MED BTU SYNTHESIS GAS	MEMPHIS	MEMPHIS TENNESSEE	1982	–

Figure 7

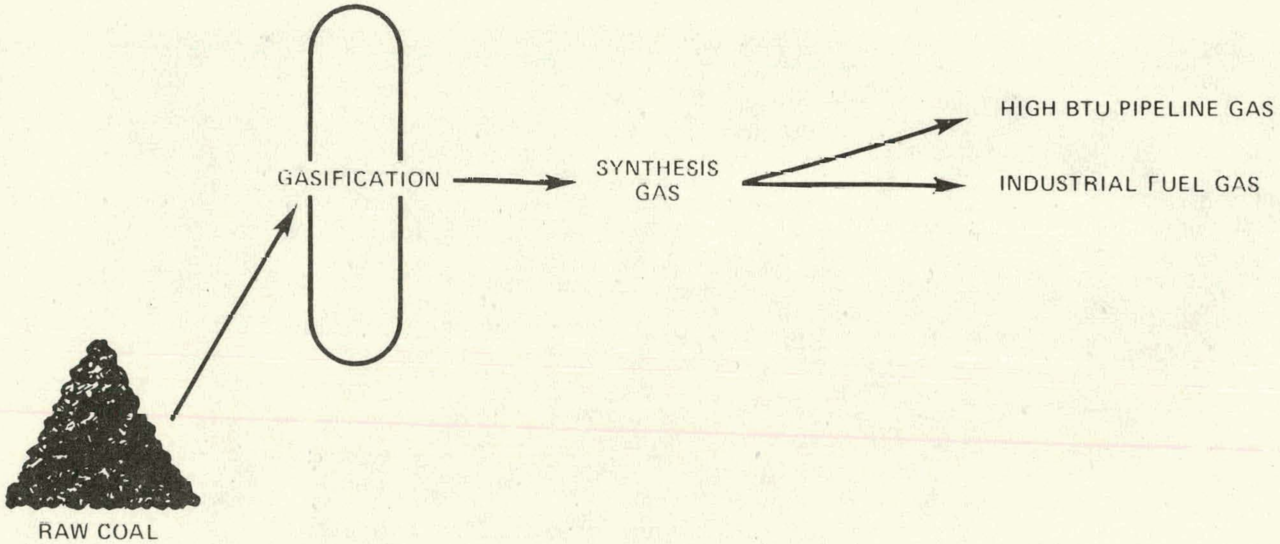


Figure 8 - Coal Conversion Process

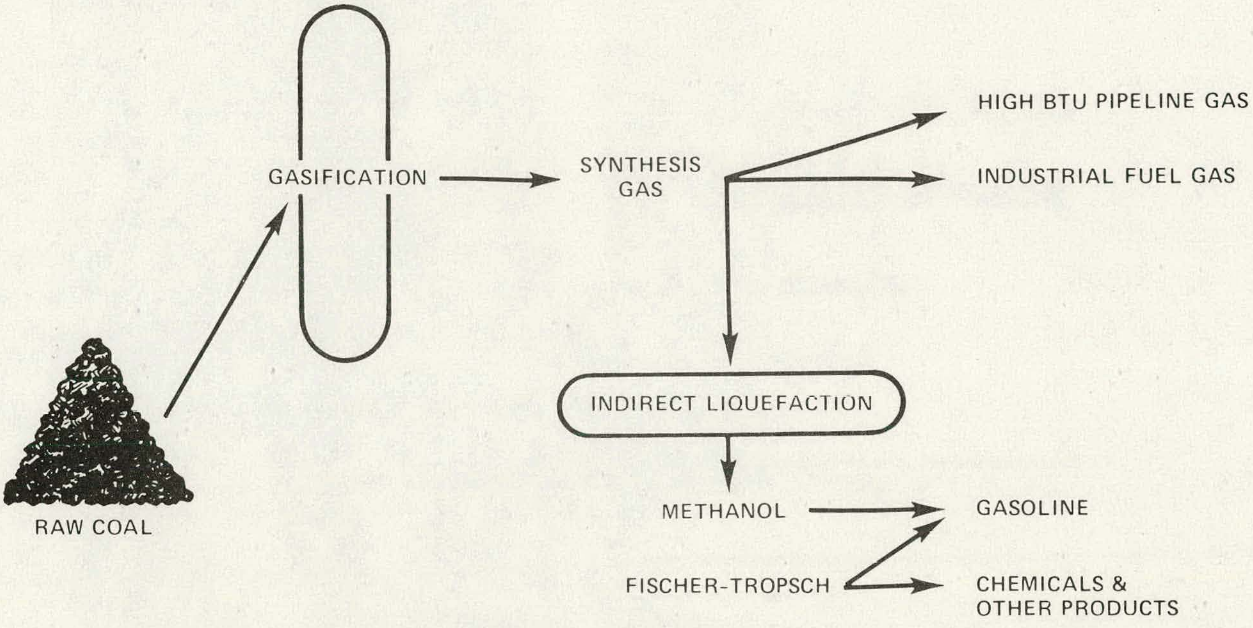


Figure 9 - Indirect Liquefaction - Synthesis Gas to Liquid

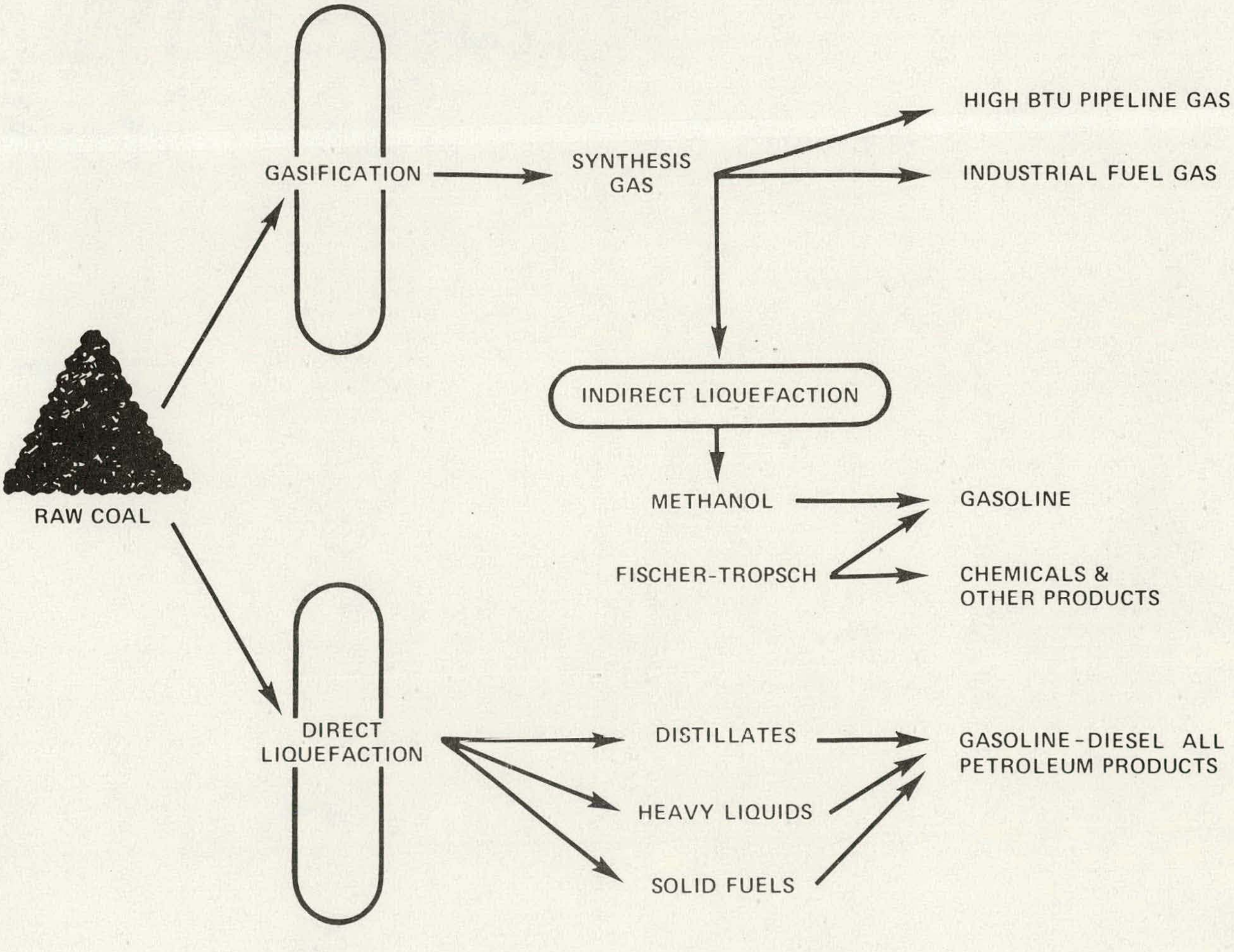


Figure 10 - Direct Liquefaction Process

MAJOR LIQUEFACTION PROJECTS

PROJECT	SPONSOR	SITE	EARLIEST PRODUCTION DEMO	EARLIEST PRODUCTION COMMERCIAL
DONOR SOLVENT PILOT PLANT (200 T/D)	EXXON	BAYTOWN TEXAS	1980	1986 (NEW SITE)
H-COAL PILOT PLANT (200 T/D)	ASHLAND OIL CO.	CATLETTSBURG KENTUCKY	1980	1986 (NEW SITE)
SRC I (SOLID) DEMONSTRATION PLANT (6000 T/D)	SOUTHERN CO. AIR PRODUCTS WHEELABRATOR-FRYE	OWENSBORO KENTUCKY	1983	1986
SRC II (LIQUID) DEMONSTRATION PLANT (6000 T/D)	GULF OIL	MORGANTOWN WEST VA.	1983	1986

Figure 11

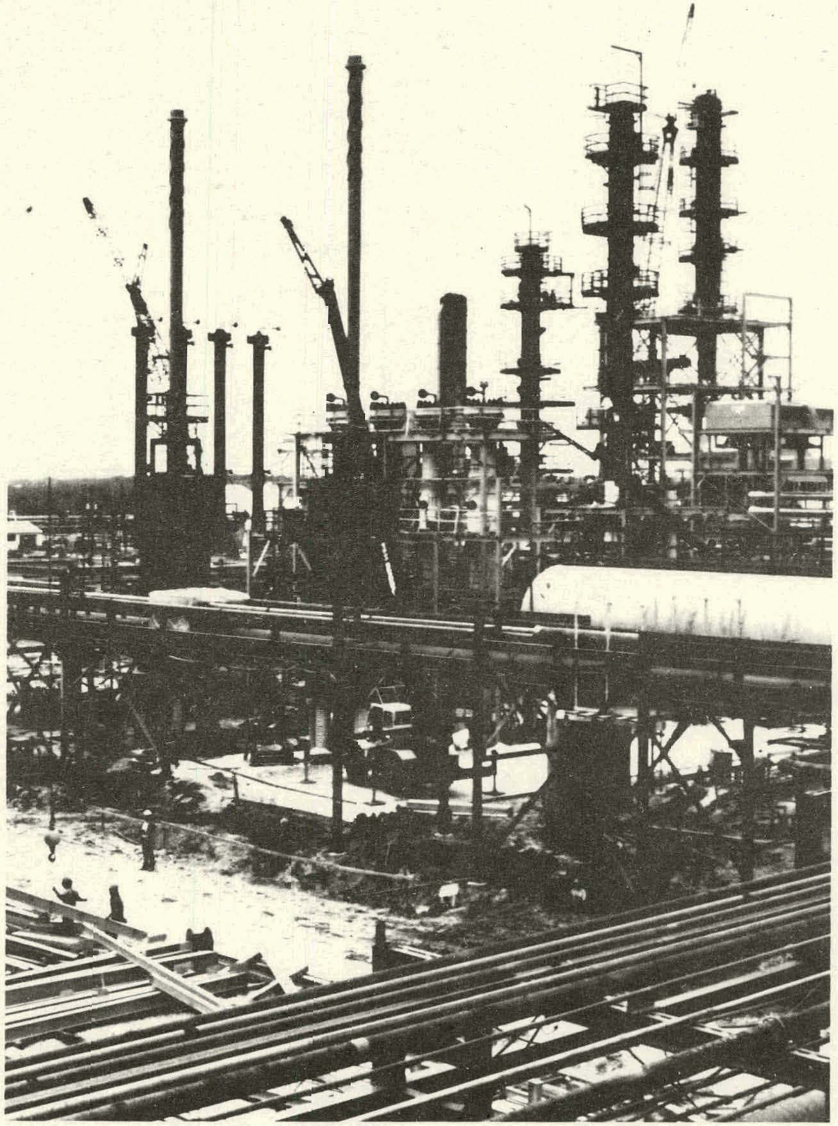


Figure 12 - Exxon Donor Solvent Pilot Plant at Baytown, Texas

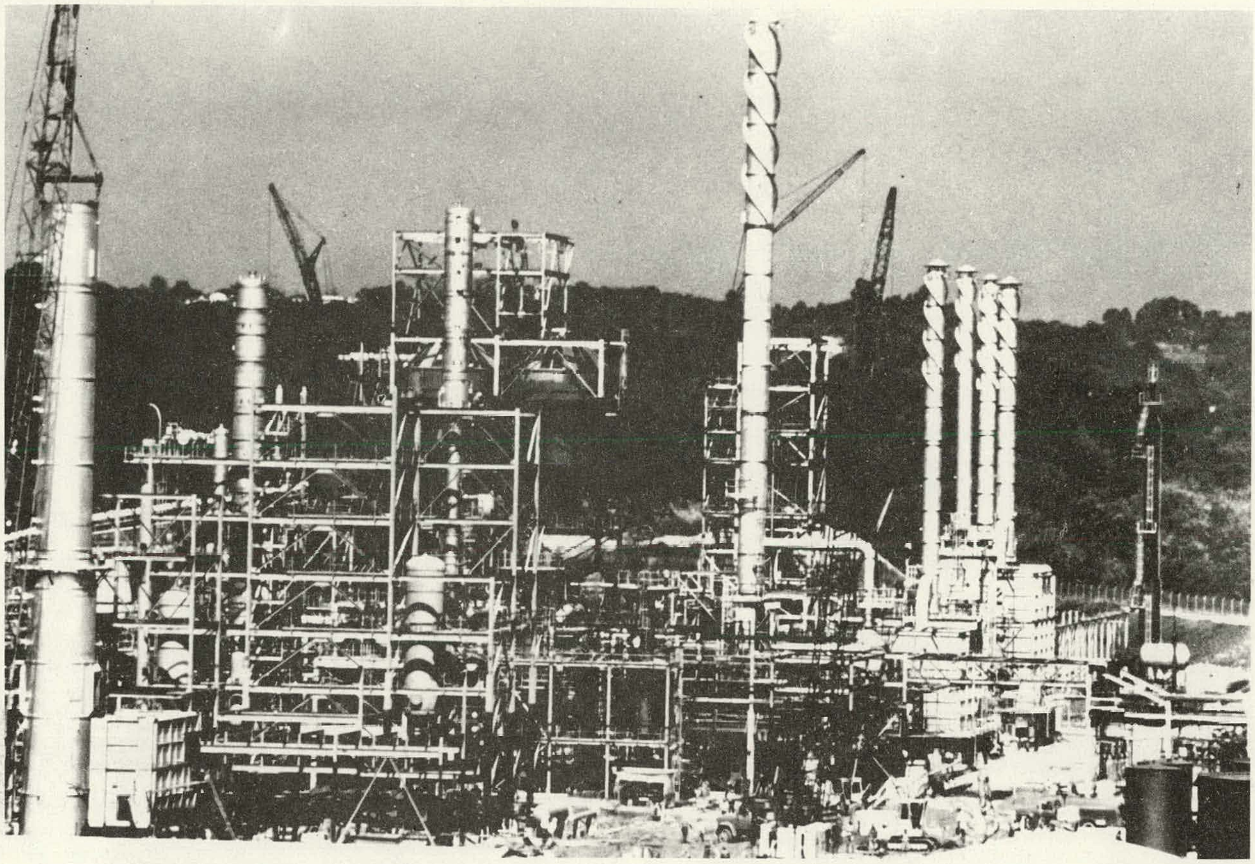


Figure 13 - H-Coal Pilot Plant at Catlettsburg, Kentucky

MAJOR LIQUEFACTION PROJECTS

			EARLIEST PRODUCTION	
PROJECT	SPONSOR	SITE	DEMO	COMMERCIAL
DONOR SOLVENT PILOT PLANT (200 T/D)	EXXON	BAYTOWN TEXAS	1980	1986 (NEW SITE)
H-COAL PILOT PLANT (200 T/D)	ASHLAND OIL CO.	CATLETTSBURG KENTUCKY	1980	1986 (NEW SITE)
SRC I (SOLID) DEMONSTRATION PLANT (6000 T/D)	SOUTHERN CO. AIR PRODUCTS WHEELABRATOR-FRYE	OWENSBORO KENTUCKY	1983	1986
SRC II (LIQUID) DEMONSTRATION PLANT (6000 T/D)	GULF OIL	MORGANTOWN WEST VA.	1983	1986

Figure 14 - Solvent Refined Coal (SRC) Processes

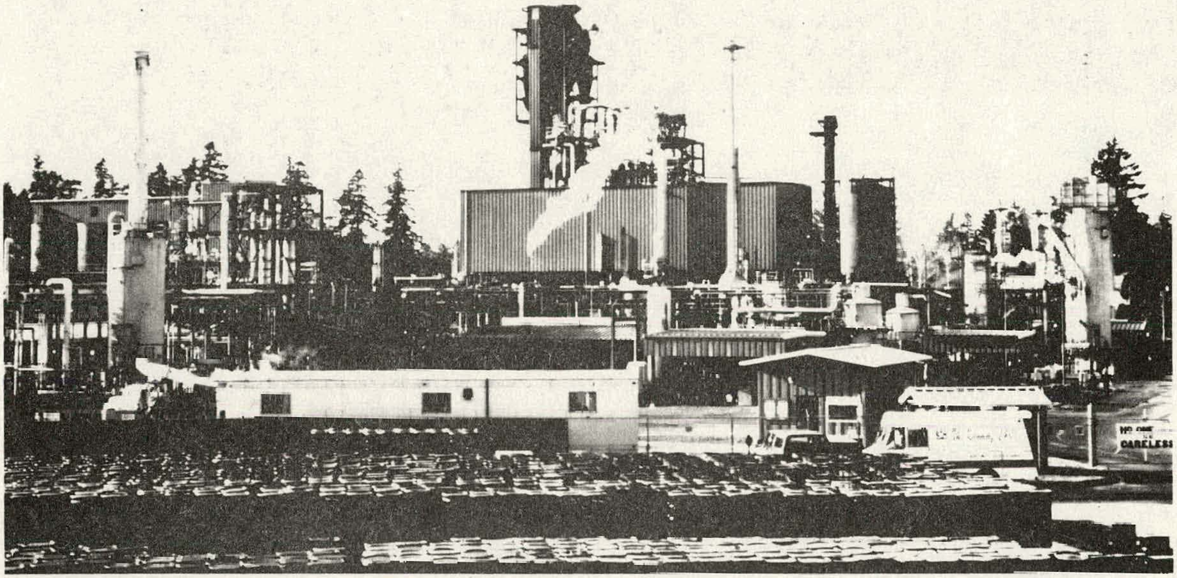


Figure 15 - SRC II Pilot Plant at Fort Lewis, Washington

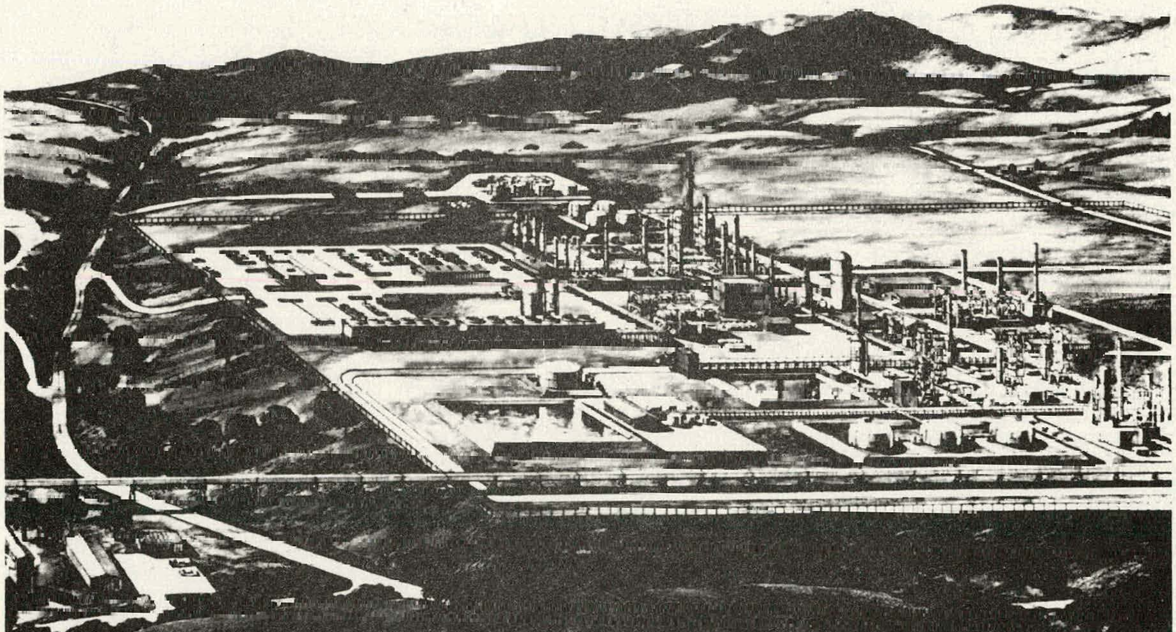


Figure 16 - Artist's Concept, SRC Commercial Scale Modules

MAJOR LIQUEFACTION PROJECTS

			EARLIEST PRODUCTION	
PROJECT	SPONSOR	SITE	DEMO	COMMERCIAL
DONOR SOLVENT PILOT PLANT (200 T/D)	EXXON	BAYTOWN TEXAS	1980	1986 (NEW SITE)
H-COAL PILOT PLANT (200 T/D)	ASHLAND OIL CO.	CATLETTSBURG KENTUCKY	1980	1986 (NEW SITE)
SRC I (SOLID) DEMONSTRATION PLANT (6000 T/D)	SOUTHERN CO. AIR PRODUCTS WHEELABRATOR-FRYE	OWENSBORO KENTUCKY	1983	1986
SRC II (LIQUID) DEMONSTRATION PLANT (6000 T/D)	GULF OIL	MORGANTOWN WEST VA.	1983	1986

Figure 17

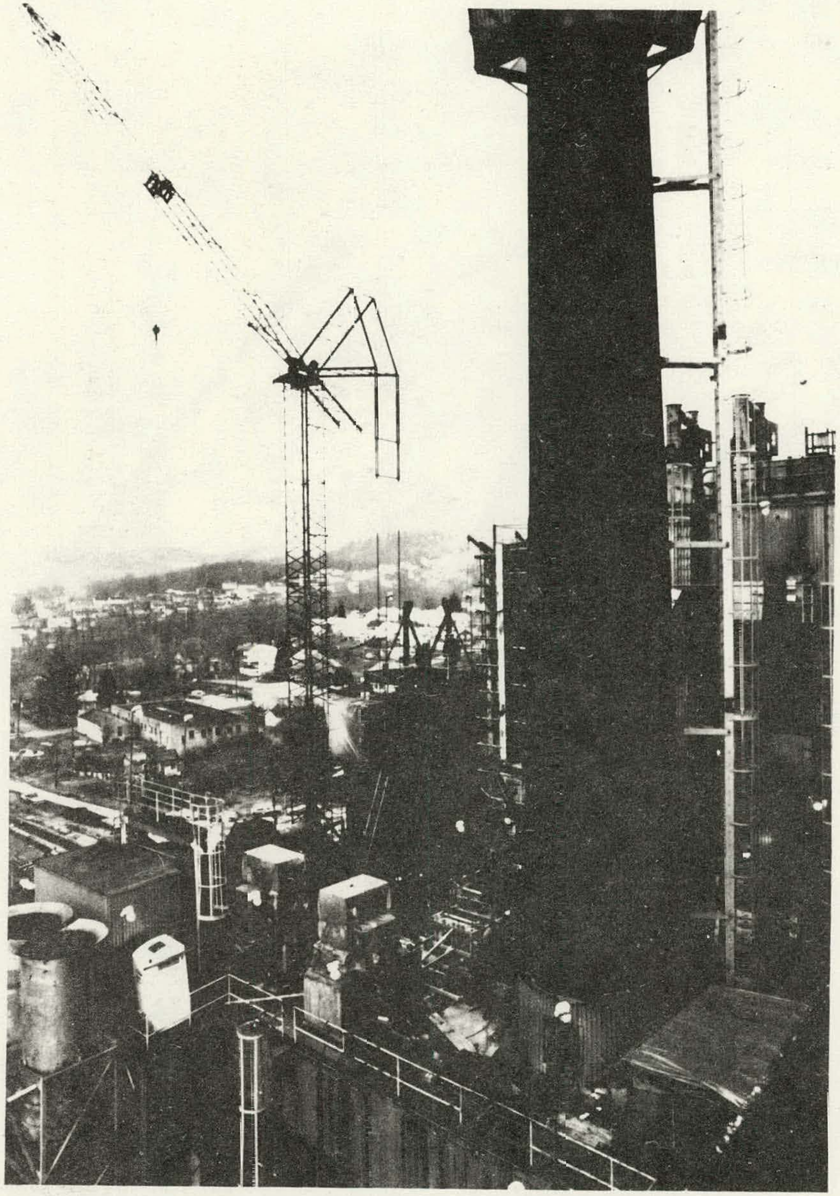


Figure 18 - Atmospheric Fluidized-Bed Combustion Project at Rivesville, West Virginia

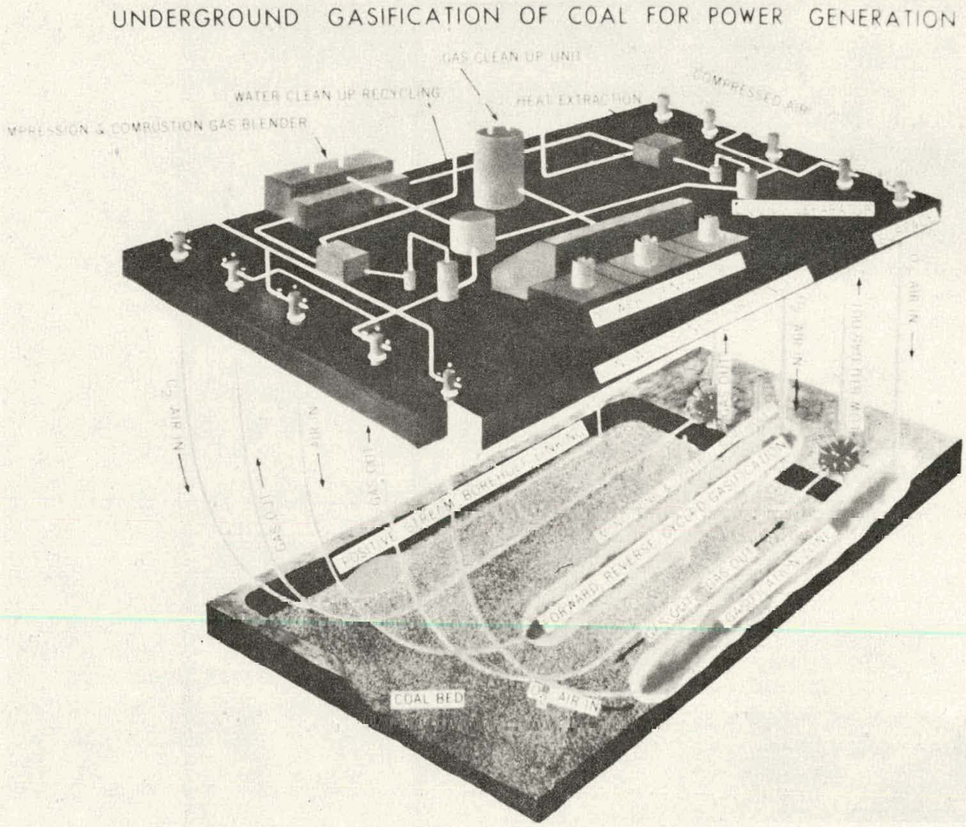


Figure 19

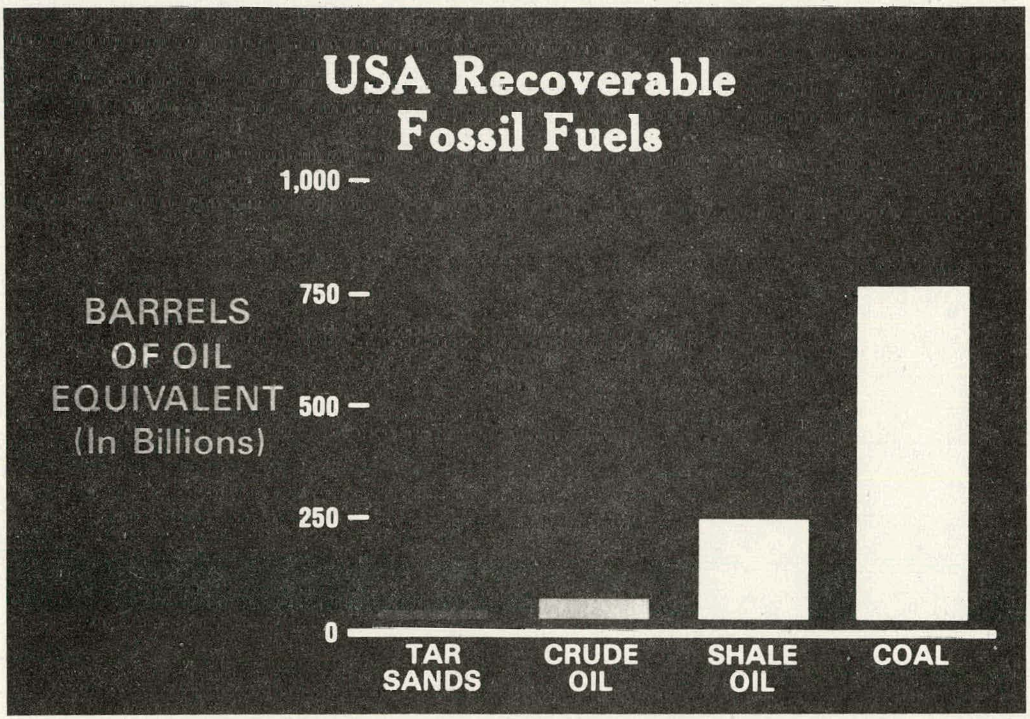
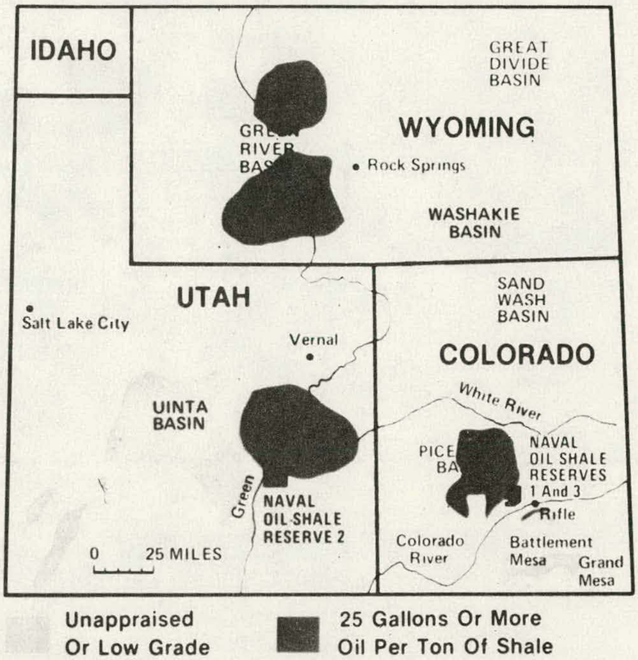
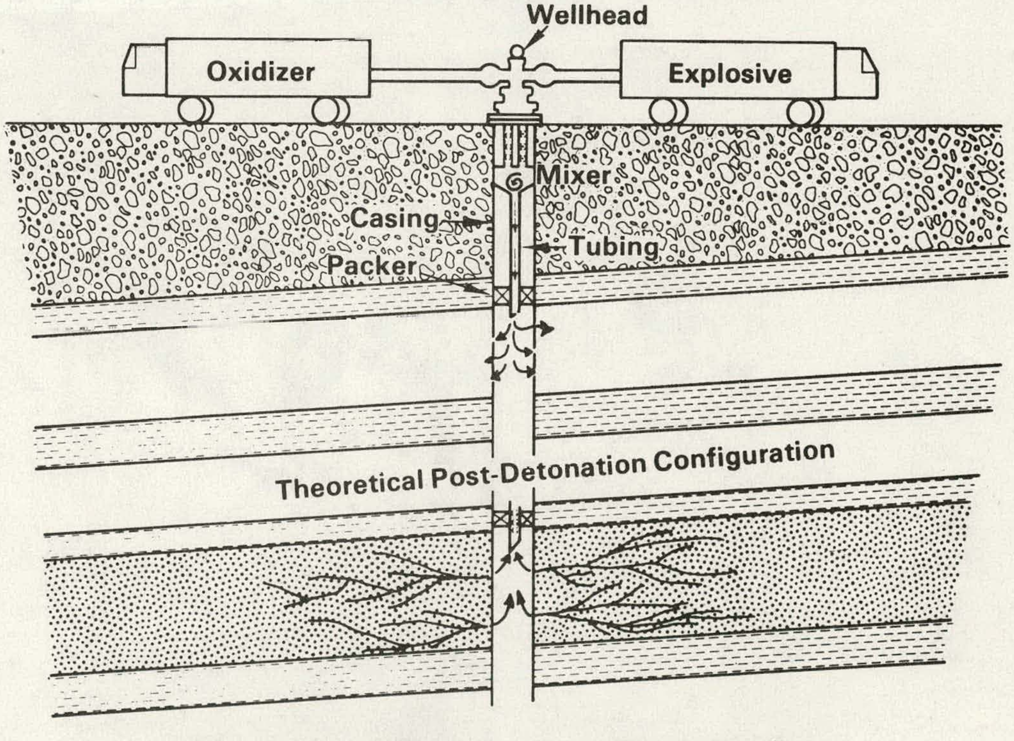


Figure 20



DISTRIBUTION OF OIL SHALE IN THE GREEN RIVER FORMATION

Figure 21



Chemical Explosive Fracturing

Figure 22

TYPICAL MHD/STEAM POWER SYSTEM SCHEMATIC

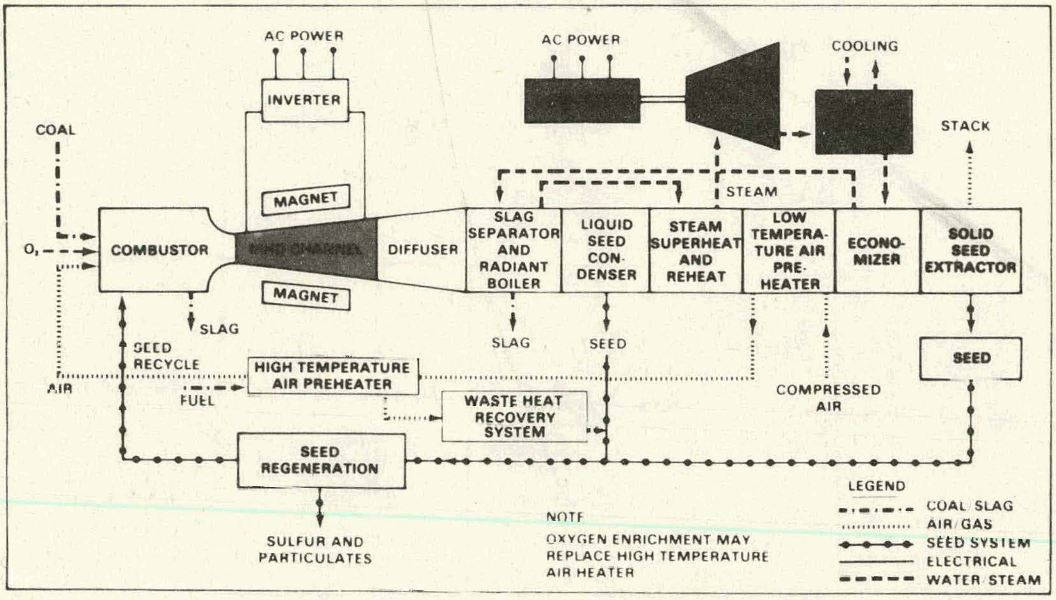
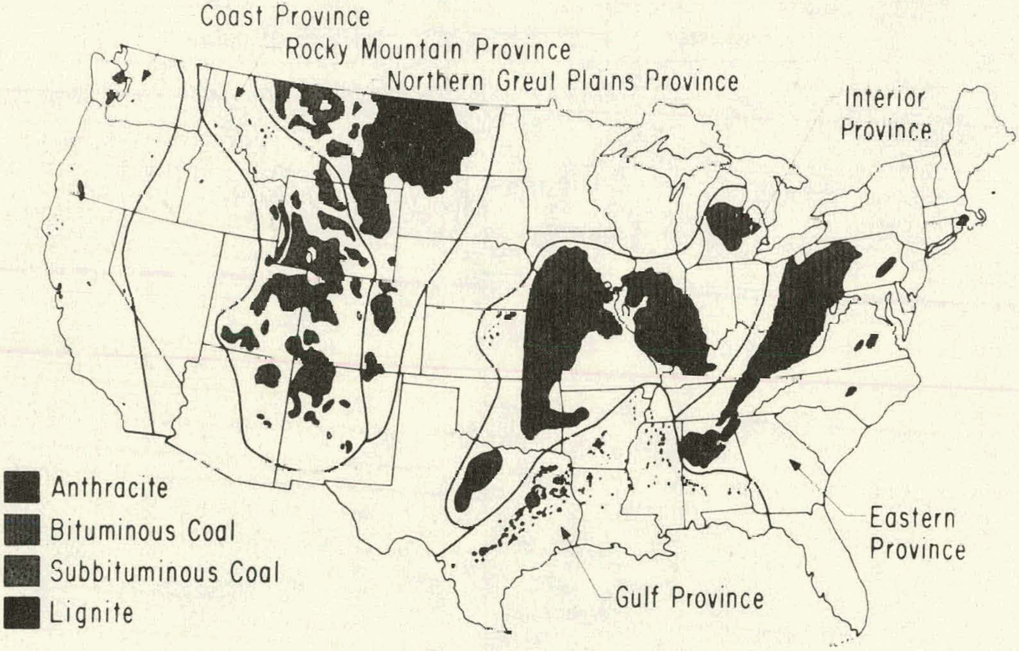


Figure 23

Distribution of United States Coal Resources



Source: Bureau of Land Management, Draft Environmental Impact Statement: Proposed Federal Coal Leasing Program (1974).

Figure 24

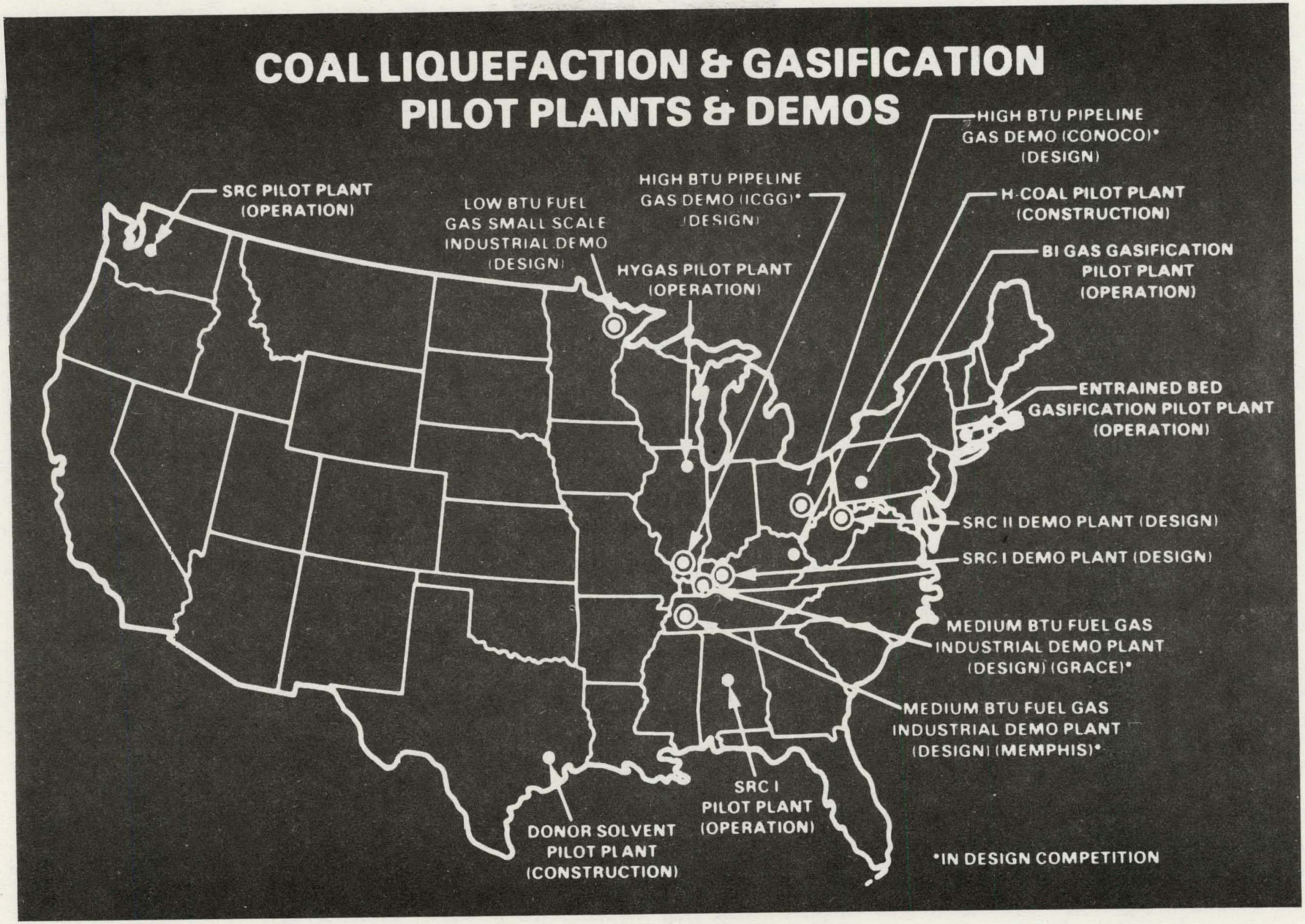

COAL LIQUEFACTION & GASIFICATION
PILOT PLANTS & DEMOS
SRC PILOT PLANT (OPERATION)
LOW BTU FUEL GAS SMALL SCALE INDUSTRIAL DEMO (DESIGN)
HIGH BTU PIPELINE GAS DEMO (ICGG)* (DESIGN)
HYGAS PILOT PLANT (OPERATION)
HIGH BTU PIPELINE GAS DEMO (CONOCO)* (DESIGN)
H-COAL PILOT PLANT (CONSTRUCTION)
BI GAS GASIFICATION PILOT PLANT (OPERATION)
ENTRAINED BED GASIFICATION PILOT PLANT (OPERATION)
SRC II DEMO PLANT (DESIGN)
SRC I DEMO PLANT (DESIGN)
MEDIUM BTU FUEL GAS INDUSTRIAL DEMO PLANT (DESIGN) (GRACE)*
MEDIUM BTU FUEL GAS INDUSTRIAL DEMO PLANT (DESIGN) (MEMPHIS)*
SRC I PILOT PLANT (OPERATION)
DONOR SOLVENT PILOT PLANT (CONSTRUCTION)
*IN DESIGN COMPETITION

Figure 25

SYNTHETIC FUELS TECHNOLOGY FROM THE INDUSTRIAL POINT OF VIEW

by

Bernard S. Lee, Institute of Gas Technology
Chicago, Illinois

I am very pleased to be back with you today, two years after I addressed this Symposium in July 1977 in Chicago. Technological aspects of instrumentation and control will be well covered in the excellent program and the previous speaker has presented an overview from the government viewpoint of RD&D on fossil fuel technology. Therefore, I will try to examine some of the basic policy and economic issues which will affect the development of synthetic fuels from an industrial viewpoint.

I am dismayed by the lack of a national commitment to develop secure domestic energy supplies. While we sit on huge domestic fossil energy resources which, if utilized, would last us hundreds of years, we continue to allow our nation to suffer the increasing burden of dependence on insecure oil imports.

Despite a gasoline shortage this summer, tight heating oil supply for the coming winter, and the mounting trade deficits, compounded by a hiatus in adding to our refinery capacity and building new power plants, we have yet to see the first shovel in the ground to build commercial synfuel plants based on our nation's bountiful domestic energy resources. While countries with lesser resources have moved and are doing what they can to increase energy supplies, our policymakers are still mired in arguments as to whether synthetic fuels are competitive with imported oil and whether we should wait for solutions that won't cost money or hard effort. Well, there aren't any such free solutions! Many people stir up public opposition by shouting that the President's synthetic fuels program is too costly because of its $88 billion price tag over the period of 1979 to 1990. Yet do these people tell the public that for each million barrels of oil we import per day, and today we import 8 times that, at a constant cost of $20 per barrel, the price to Americans is $88 billion over the same 12-year period? Opponents to synthetic fuels piously point their fingers at the possibility that synthetic fuels development may cost more because of inflation and cost overruns. But do they remind the public that imported oil has not exactly stood still, that it has gone from $14 to $21 per barrel in the first six months of this year alone?

We are not yet in a position to apply marginal cost economics as a criterion for selecting energy options. We can apply marginal cost economics and a free market approach to international trade in television sets, automobiles, steel and machinery, for all of which we have commercial production capability in this country, so that with respect to these commodities we are in a posture of "potential independence" from imports. At any time, if dependence on imports becomes unacceptable, we have the full capability of producing these goods domestically. But the same capability has not yet been developed with respect to energy, and until it is, we will have only worsening energy dependence and growing trade deficits and inflation, leading not only to economic chaos but also to a loss of national security.

The importation of oil from OPEC countries does not fall under the rules of a normal free market approach. Not only is the demand just moderately price-elastic, but more importantly, the supply is determined by the production policies of the OPEC members and not by normal economic considerations. Therefore, as the price of oil rises, the supply not only may not increase, but may in fact decrease to return the same revenue to the OPEC countries. This trend is already established in the current actions by the OPEC nations of adjusting production to keep the market tight and the price high. Thus, it is totally out of place to use a free-market approach to determine the appropriate time for launching a synthetic fuels industry when there is no free market.

I mentioned a moment ago the widely prevalent belief that synthetic fuels are not competitive with imported oil. This would seem to be true when the posted price of imported oil, say $20 per barrel, is compared with the estimated cost of synthetic fuels, generally in the range of $25 to $50 per barrel oil equivalent. However, the results of preliminary studies carried out at IGT indicate that reasoning based on this relationship is fallacious. We took a look at the major external costs associated with oil imports. Before proceeding, let me define the meaning and role of externalities. When a cost or benefit is incurred by someone other than the producer or buyer, it occurs outside the market transaction and is thus an externality. An external cost occurs when part of the cost of producing or using a good must be paid by someone other than the firm which produced it or the individual who consumed it. Prices, thus, do not always reflect all the cost incurred in producing or using a product. For example, manufacturers poured smoke relatively freely into the air when they did not have to pay the cost of environmental clean-up. Externalities create the case for government intervention to either set standards to end the externalities or to set payments on the market transaction such that those who incur external costs are compensated or those who incur external benefits contribute in a market transaction.

The United States in largely the last decade has passed a series of environmental protection laws which have lessened the externalities of indigenous energy supplies. The external costs are now part of the firm's production costs and are reflected in the market price or the direct cost. For example, the price of coal from strip mines now includes a charge to cover the cost of reclaiming the land. Land reclamation has been made part of the firm's costs by public policy. The externalities, in the jargon of the economist, have been internalized. Many new energy technologies such as SNG from coal have had many of the externalities associated with air, water, or land pollution made part of the production costs. Thus, the U.S. has seen the direct cost of these energy sources rise rapidly while the external costs have largely disappeared.

The consumer of imported oil is largely spared the external costs, and the external costs are not felt by the consumer when he makes his market transaction. Thus, the cost of imported oil is lower than if the cost reflected associated externalities of inflation, unemployment, and national risks. This causes a biased cost comparison leading the consumer to overconsume oil imports in much the same fashion that the manufacturer once polluted the air. The United States needs to expand the principle of externalities to include foreign oil imports.

To summarize the study, IGT estimated the externalities of reducing oil imports: improved trade balance, lower oil prices, added real dollar output through decreased dollar leakages to foreign countries and decreased supply disruption costs due to less dependence on imported oil. These externalities, when added to the base cost of the imported oil, indicate a true cost of imported oil between $40 and $55 per barrel, or about $7 to $9.50 per million Btu. On this basis, practically all of the alternate fuel technologies available and under development would be cost effective immediately.

The President has proposed a program to reduce substantially the nation's dependence on oil imports by 1990. The program is ambitious, but, in my opinion, achievable, if the nation approaches this program with a total commitment and mobilization of its human, technical and financial resources. I believe the American people understand the energy crisis and are ready to respond to the challenge of solving the energy problem on a permanent basis through the development of domestic energy resources.

The two mainstays of a realistic energy policy are expanded energy supply and increased energy conservation. The nation needs both. Those who claim that conservation alone can solve the energy problem for the long term mislead the public and do themselves and the nation irreparable disservice.

It is imperative to begin immediately the energy supply options, especially synthetic fuels, because it takes long lead-times plus large capital to develop these options. The gaining of several years of time by concerted action now can more than pay for the cost of development, given the true cost of imported oil and recognition of the fact that it will cost even more in the future.

Although the President's program deals with large-scale commercial deployment of various technologies to achieve a substantial oil import reduction, it is also imperative that well-planned programs for research, development and demonstration be continued to maintain the flow of technological innovations and improvements. The President's program establishes the mechanism for launching the synthetic fuels industry on a broad front. This vital step in no way diminishes, and in fact demands greater emphasis upon, the need for solid research and development to support the massive commercialization effort.

The supply segment of the President's program contains two major elements which I wish to address. These are (1) the development of 2.5 million barrels per day of oil substitutes with liquids and gases from coal, peat, oil shale, biomass and unconventional gas; and (2) the requirement to cut utility consumption of oil by 0.75 million barrels per day.

I have outlined a program that would achieve these targets through two waves of deployment. The first wave consists of deploying several commercial plants using currently available technologies, while simultaneously deploying demonstration plants for a number of advanced technologies to establish their commercial viability. The second wave will then come in the mid-80's for deploying commercial plants based on demonstrated advanced technologies. Those first-wave commercial plants will continue to be feasible because of the cost escalation during the time period while advanced technologies are being demonstrated. These plants will also provide a real reference for production cost, performance and environmental data. The second-wave commercial plants will be more efficient and economical than the first wave and will be the basis for the competitive growth of the synthetic fuels industry.

In my program, I have indicated the number of demonstration and commercial-size plants needed as well as when and where these should be deployed. The number of plants represents the number of commercial-size units. Some locations may support more than one unit. Similarly, a demonstration plant can be expanded to a commercial-size plant at the same site. Specifically:

- As to the split between gaseous and liquid fuels, since (1) gaseous fuels can be substituted directly for oil in essentially all stationary applications, (2) gas represents a finished product of high form value, and (3) the cost of gas production is lower than that of liquids, IGT recommends that at least half of the target goal be synthetic gases.
- IGT recommends that the fossil resources in the East be strongly emphasized because:

a. the recoverable bituminous coal resource in the East is at least as great as that of lignite or subbituminous coal in the West, and similarly for Eastern shale relative to Western shale.

b. water is much more available in the East.

c. markets are much closer to the points of production in the East.

d. the skilled manpower pool and manufacturing resources are greater in the East.

- To fully utilize coal, both high- and medium-Btu gasification plants should be on-stream. Medium-Btu gas plants can economically serve industrial users concentrated within a relatively small radius, while high-Btu gas plants can be connected to the existing natural gas transmission and distribution network to serve residential, commercial and industrial users.
- In the area of oil shale, the President's target of 0.4 MMB/D oil equivalent by 1990 can be achieved by simultaneously developing shale resources both in the West and in the East to produce both high-Btu gas and liquids. The Eastern shale resources, in addition to being close to the population centers, with much more water availability, have a more favorable shale chemical composition that minimizes leaching, and should be developed via advanced hydrogen retorting technologies.
- The President's targets for biomass and unconventional gas appear reasonable.
- To achieve a 50% reduction of oil use in utility boilers, a logical approach is to replace oil with clean fuel gas from Eastern coal, since many of these boilers are concentrated in the East. At least half of the President's target should be met by making use of advanced gasification and combined-cycle technology that not only provides clean fuel but also higher efficiency of power generation.

In summary, total synthetic gases, both high- and medium-Btu, to provide oil substitutes and to reduce the use of oil in utility boilers amounts to 1.15 MMB/D oil equivalent by 1990. The total synthetic liquids - from coal, oil shale, and biomass - amounts to 1.0 MMB/D oil equivalent. Table 1 summarizes the 1990 synfuels plant deployment I have outlined. The capital investment, in 1979 dollars, excluding mining investment, would be about $90 billion for synthetic fuels production. This figure is very close to that proposed by President Carter for the Energy Security Corporation.

A massive commitment of financial and human resources will be necessary to carry out this ambitious program. Since time is short, action must start immediately to resolve the regulatory and institutional constraints. A rational and workable balance between environmental and energy goals must be established and maintained. The adversary stance of government and private industry must be reversed to one of mutual cooperation. If we can accomplish these objectives and start developing a synthetic fuels industry, the benefits will increase commensurately with the commitment. The security of energy supply will increase, our national defense posture will be strengthened, the price rise of imported energy will be moderated, and the U.S. can formulate and implement national and international policy free of the constraints imposed by overdependence on foreign energy supplies.

Let me close by citing what Astronaut (now Senator) John Glenn said during an address to a joint session of Congress in 1962: "People are afraid of the future, of the unknown. If a man faces up to it and takes the dare of the future, he can have some control over his destiny. This is an exciting idea to me, better than waiting to see what's going to happen."

We as a nation must take this attitude and make the move to synthetic fuels now.

Implementation of Two Elements of President Carter's Program

A) Target: 2.5 MMB/D oil substitutes with gases and liquids from coal, peat, oil shale, biomass, and unconventional gas by 1990

Oil Equivalent, MMB/D

1) Coal Gases and Liquids 1.25

- o 15 high-Btu gas commercial-size plants, 6 in West, 9 in East, each 250 X 10^9 Btu/D
  Total 0.6 MMB/D
  - i) Deploy now 3 Lurgi commercial plants in West
  - ii) Deploy now 3 demo plants in East for advanced technologies
  - iii) Deploy in 1986 using advanced technologies:

    3 commercial plants in West

    9 commercial plants in East (including 2 using peat)
- o 5 medium-Btu industrial fuel commercial plants, each 100 X 10^9 Btu/D
  Total 0.1 MMB/D
  - i) Deploy now 2 demo plants in East
  - ii) Deploy in 1985, 5 commercial plants in East
- o 11 coal liquids plants, each 50,000 B/D
  Total 0.55 MMB/D
  - i) Deploy now 3 SASOL-type plants in West
  - ii) Deploy now 3 demo plants for advanced technologies, 2 in East, 1 in West
  - iii) Deploy in 1986 using advanced technologies:

    3 commercial plants in West

    5 commercial plants in East

	Oil Equivalent, MMB/D
2) Oil Shale	0.4
o 7 shale liquids commercial plants, 5 in West, 2 in East; 1 Eastern shale, high-Btu gas commercial plant	
i) Deploy now 5 Western shale liquids commercial plants, each 50,000 B/D Total 0.25 MMB/D	
ii) Deploy now 1 Eastern shale demo plant	
iii) Deploy in 1986, 2 Eastern shale liquids commercial plants, each 50,000 B/D, and 1 Eastern shale, high-Btu gas commercial plant, 250 X 10^9 Btu/D Total 0.15 MMB/D	
3) Biomass	0.1
4) Unconventional Gas	0.75
Production Capacity Total 1990	2.5 MMB/D

B) Target: <u>0.75 MMB/D oil reduction in utility boilers by 1990</u>.

1) Coal Gasification in Combined Cycle	
20 commercial plants, each 100 X 10^9 Btu/D or 500 MW	0.4
i) Deploy now 3 demo plants in East	
ii) Deploy in 1986, 20 commercial plants, mostly in East	
2) Other Oil Displacements, e.g., Fluidized Coal Combustors, Direct Coal Combustion with Stack Gas Cleanup	0.35
Reduction Total 1990	0.75

TABLE 1

1990 SYNFUELS PLANT DEPLOYMENT

	EASTERN STATES	WESTERN STATES	ENERGY OUTPUT 10^9 Btu/DAY	ENERGY OUTPUT 10^6 BDOE
COAL-TO-SNG	7	6	3250	0.5
PEAT-TO-SNG	2	—	500	0.1
COAL-TO-FUEL GAS	5	—	500	0.1
OIL SHALE-TO-SNG	1	—	250	0.05
OIL SHALE-TO-OIL	2	5	—	0.35
COAL-TO-LIQUIDS	5	6	—	0.55
COAL-TO-COMBINED CYCLE (Barrels of Oil Displaced)	14	6	2000	0.4
OTHER POWER PLANT DISPLACEMENTS				0.35
BIOMASS				0.1
UNCONVENTIONAL GAS				0.75
			TOTAL	3.25

PROGRESS SINCE THE 1978 SYMPOSIUM, AND FUTURE NEEDS IN INSTRUMENTATION AND CONTROL FOR FOSSIL ENERGY

T. K. LAU
Department of Energy

INTRODUCTION

I would like to add to the warm welcomes already extended to you this morning. It is always a pleasure to see such an attendance at a gathering of this type. More than that, I am pleased to welcome you to the third in this series of symposia. Many of you may recall our first meeting in Chicago. Our main purpose at that time was to familiarize as many as possible with the nature of our task and the scope of our challenge. At the outset we had no assurance that there would be a second symposium. Those of you who attended the meeting at Newport Beach last year may recall that a number of the presentations were in the nature of progress reports. The success of that meeting was largely due to your participation and support.

As a result, we are beginning our symposium and again an underlying theme is progress. Those who have preceeded me this morning have eloquently stated the case for our being here. One point might well deserve some reinforcement. Many of you have been confronted with the idea that the instrumentation challenges can easily be handled sometime downstream. As we well know, in terms of today's emerging technologies nothing could be further from the truth. At no time in history have the instrumentation designers and manufacturers been faced with such a tremendous challenge. During the last two decades our colleagues in the nuclear field have been confronted with almost overpowering challenges to meet the reliability, safety, and environmental requirements of society. There is no reason to believe that our challenge will be any less.

The very nature of the programs in which we are about to participate is also testimony that there are instrumentation and control problems for which solutions are urgently needed.

During the remainder of this day we will hear several papers which describe some process experiences which tend to bring into focus some of the challenges facing us. Tomorrow there will be reports outlining our progress in the areas of flow measurement and sampling and analysis. Tomorrow afternoon we will once again have a process clinic. This feature has been included in the program by popular demand. There was a session of this type included in the first year. So many of you found it valuable that we have included it again this year.

The process clinic will be followed by the annual show and tell session which highlights problems and solutions. We encourage all of you to take advantage of this opportunity to either celebrate or commiserate with your colleagues who have front line experience with problems.

On Wednesday the major themes will be analysis on control, and on temperature, level and pressure instrumentation. In addition, an Instrumentation and Equipment Exposition will be held for 2 1/2 days in the Rocky Mountain Ballroom. We urge you to take full advantage of these sessions and expositions. To the fullest extent possible, let us share your experience and insight.

PROCESS AND ACCOMPLISHMENT

What have we accomplished since last year? In the Argonne National Laboratory (ANL), our major I&C program supporter since 1975, the two phase, solid and gas, mass flow test facility (S/G FTF) was completed (Figures 1,2,3). This facility provides separately measured air flow up to 200 CFM and separately controlled solid flow up to about one pounds per second. Although minor improvements are still being made, the facility will be used to test the feasibility of in-house developed prototype instruments as well as to evaluate the performance of commercially available instruments. For example, the ANL developed capacitive mass flow prototype instrument (Figure 4), the Auburn International patented three phase electric capacitive transducer for density component of mass flow measurement, the dual Gamma Ray Density Velocity meter for dense phase mass flow measurement (Figure 5), and the optical particulate monitor developed by the Spectron Development Laboratories (Figure 6), are scheduled for evaluation in this facility.

An acoustic flow/no-flow device was built for the Bi-Gas Pilot Plant at the steam-char return line at the request of plant personnel (Figures 7,8,9,10). The device was installed and tested during a regular period of plant operation. The results were successful, so that investigation for quantitative flow measurement is now underway. On the slurry feed line of the HYGAS Pilot Plant where an acoustic test rig was installed (Figures 11,12), initial tests indicate that the noise background and attenuation are sufficiently low in the appropriate frequency range that an ultrasonic flow device will be feasible for slurries with high solid concentrations. A capacitive device was built and installed in the HYGAS slurry line to measure density and, via cross-correlation, flow velocity. Initial tests indicate qualitative agreement of the indicated density with measured density of samples. Velocity measurements which correspond well with calculations were obtained in a few seconds. Tests of this device as well as the acoustic tests are continuing at the HYGAS Pilot Plant

The sonic Doppler shift principle is also investigated for the measurement of high concentration coal slurries (5-40% solid) (Figures 13,14). A noninvasive system having a transducer on the outside of the pipe is essentially attractive for safety and convenience in operation and maintenance. The ideal single frequency scattered energy is not realized in practice but a broad band of scattered energy is observed. The spectrum has a definite maximum value close to the expected Doppler frequency. Further details on the acoustic and capacitive mass flow measurements will be presented on Tuesday morning under Session A - Flow Instrumentation Control.

In the area of process analysis a software package for quantifying instrument requirements within acceptable limits was developed sufficiently for testing on a model of a methanation unit. Tests on two simple systems were made at intermediate stages of development of the computer code.

Since the 1978 Symposium, personnel of the National Bureau of Standard (NBS) Measurements Division have been working with the Bi-Gas Pilot Plant personnel, under a cooperative DOE contract, to develop more durable thermocouple assemblies for the temperature measurements. Measuring the temperature in the slagging section (Stage 1) of the Bi-Gas Pilot Plant gasifier on a continuous basis has been a persistent problem for pilot plant personnel (Figure 15). The life of thermocouple assemblies used for such measurements has typically been less than 100 hours owing to failure of the protective thermowells by corrosion or erosion, or both.

In this project, three types of prototype thermocouple assemblies have been designed and constructed by NBS personnel for use in the slagging section of the gasifier, where temperatures range from 2500 to 3000°F. All three types employ commercially built W-5% Re versus W-26% Re thermocouples that are sheathed with molybdenum tubes having a molybdenum deselicide coating. The thermocouple is contained within a protective thermowell. Each type of assembly uses a different material for the thermowell. The three thermowell materials selected for use with the initial prototypes are:

1. Chemically vapor deposited silicon coilide.
2. High purity sintered beryllium oxide, and
3. A molybedenum-zirconia cermet.

Photos of these thermocouple assemblies are shown on Figures 16,17.

NBS personnel have also constructed thermocouple assemblies for the entrained bed section of the gasifier (Stage 2) where temperatures range 1500 to 2000°F. Post-test examinations by NBS of the thermocouple assemblies presently used in this section of the gasifier revealed that the steel thermocouples used experience very little corrosion or erosion but that the type K thermocouples contained in thermowells exhibit changes in thermoelectric output equivalent to more than 40°F after only 200 hours of gasifier operation. These changes were found to be the result of preferential oxidation of chromium in the nickel-9.5% chromium leg of the thermocouple. The replacement thermocouple assemblies constructed at NBS for the entrained section of the gasifier consist of stainless steel sheathed nicrosil versus misil thermocouples contained in alonized Type 310 stainless steel thermowells.

The first group of NBS prototype assemblies were delivered to the Bi-Gas plant early this year and are presently undergoing evaluation in the gasifier. It is planned that this project of high temperature thermocouple assemblies evaluation will be expanded to other pilot plants and demonstration plants. Further information about the NBS work can be obtained at the NBS display at the Show and Tell Session. In addition, a paper by NBS describing this program will be presented Wednesday afternoon.

FUTURE NEEDS

Now I would like to look into the future needs in instrumentation and control for fossil energy process. Development of second and third generation conversion processes for fossil fuels has created an urgent need for instruments for measurement and control that is not generally being met by the usual commercial equipment suppliers. There are requirements created by the emerging energy technologies for which there are currently no satisfactory solutions. This situation has been recognized, and since 1975, the Argonne National Laboratory has been conducting an instrument development program to meet some of these needs.

In July 1978, at the request of the Department of Energy, the Jet Propulsion Laboratory (JPL) began work on a general plan for the development of needed control instrumentation over a five year period. The purpose of this plan is to provide a Reference Document that the DOE can use to establish guidelines for defining, scheduling, and funding an instrument development program. Such a program would be a continuation and expansion of the work now going on. The program goal is to provide developers of fossil energy processes with the timely commercial availability of the measurement and control instruments which are required for the efficient, reliable, and long life operation of fossil fuel conversion plants. This timely availability is not expected to be realized without stepped-up government encouragement and coordination as incentives in the high risk areas of instrument development. This is a plan which is not presently matched by actual budget.

Measurement and control problems in advanced fossil fuel processing are concentrated in the areas of new conversion technology, involving mixed-phase conditions in and around the reactor. Figure 18 sets the boundary for major instrumentation and the control problem area. Needs have been identified in all advanced fossil fuel conversion processes, including coal liquefaction, coal gasification, fluidized bed combustion, oil shale processing, and coal-fired MHD. Furthermore, the most critical development needs are at the component level: Those on-line end instruments and control devices operating in the actual process streams. The emphasis of this program plan is therefore limited to high risk component development in specifc areas. Although not specifically discussed, application to other fuel conversion processes including solid wastes, biomass, wood chips, formcoke, and peat will also be included.

The program for development of instruments, as provided by JPL, addresses five specific current needs:

a) Mixed-phase mass flow measurement

b) Level measurement

c) Reactor temperature measurement

d) On-stream composition analysis

e) Particle detection

Generally, development of a new instrument may proceed in four steps:

1. Establish the Requirements and Specifications

2. Contract for Prototype Component Development for Commercial Source

3. Provide Alternate Development such as from a National Laboratory -- should industry respond to prototype development be unsatisfactory.

4. Perform Testing and Performance Qualification.

The accepted components will become the basis for establishing qualified commercial sources for these instruments and control devices.

Technology transfer is an important aspect of technology development. This is the means by which new and developing technology in component design and testing is reported to potential equipment suppliers and users. The dissemination of measurement and control information and the transfer of technology among participating agencies and industrial organizations is critical to an efficient development program. Support of major symposia on instrumentation and controls is a part of the proposed program plan. Commitment for an uninterrupted series of annual symposia on Instrumentation and Control for Fossil Energy Processes, of which this is the third, is recommended. Funding is called for as well for an Instrument and Controls Newletter to be published periodically.

Involvement by component manufacturers would be actively promoted in instrument development conducted under the JPL proposed program plan. A list of qualified and interested vendors would be maintained, and regular contacts made with design and marketing personnel. Requirements and specifications for components would be drafted with industry participation, to maintain interest by manufacturers in this activity, and so that requirements reflect a realistic balance between needs and capabilities. Manufacturers will participate in establishing test requirements and evaluation criteria. Results of tests will be widely reported, and manufacturers' comments solicited and reviewed.

The JPL program plan also proposes the establishment of an industrial advisory group, comprised of representatives from the user community. This group would review the instrumentation and control program periodically, provide guidance and recommendations to improve the program, and assist in integrating new instrument and control systems into fossil fuel plants. Through this group industry should gain insight into the government program, influence the government program to meet the needs of industry, and have the opportunity to promote early introduction of new technology. Membership of this group would be drawn from plant designers, instrument manufacturers, utility companies, and associations such as EPRI and GRI, and government agencies.

A major part of the instrumentation and control program plan is a supporting technology activity which would provide the specific and advanced technology base for instrument development. Supporting technology includes measurement studies and evaluation, process control review, environmental and safety studies, advanced concept development, and - coordination with cost shared industrial partners of the fossil fuel demonstration plants.

Process modeling and error analysis make up the measurement studies activity. Existing process modeling programs would be expanded to include measurement relationships. Modeling would be used to determine the compatibility of various measurement/control schemes for effectiveness, seeking alternatives to traditional but difficult measurement methods. The effect of instrument error and response on process operation would be studied, with the objective of establishing realistic and appropriate component accuracy requirements.

In the plan, emphasis on conceptual studies and advanced development is equal to that placed on current technology development. Work would be on the new technology of today. Examples of such activity already underway are the projects at ANL and SAI to measure mixed-phase mass flow by neutron activation and by gamma ray correlation. Significant support would be given to instrument innovators by sponsoring feasibility studies and concept development contracts. It is expected that this activity will provide a foundation for commercial instrument availability for the future.

Extensive testing will be required to support new equipment development. It is expected that much of the new design information will come from the results of experimental testing. Purchased prototype hardware must be qualified through a formal test program. Additionally, it will be necessary to demonstrate new concepts and equipment to plant designers and operators, not only in test facilities, but in pilot plants. However, there is today a serious shortage of adequate test facilities for instrumentation and control components. Industrial manufacturers do not have the large scale test capability required to test instruments with mixed-phase flow, high temperaturers, high pressures, and sufficient flow capacity. Several government-owned facilities are doing testing now, but in one or more of the above areas they are deficient. Pilot plants fill a need for component demonstration, but testing is hampered by being on a noninterference basis with process operation, and the absence of controlled, known operating conditions. The instrumentation and control program plan provides for the definition, buildup and operation of major component test systems.

The advancement of instumentation and control technology is basic to the development, demonstration, and evaluation of the various fossil fuel utilization processes because it affects not only process operation and control, but plant efficiency, plant reliability, plant safety, process performance evaluation, and pollution control. Benefits in these areas will result from this proposed program plan for the improvement of instruments for measurement and control.

An example of the tangible benefits to be expected is the potential return from improved instrument reliability. An inoperative or malfunctioning instrument can close down an entire process line. More reliable instruments mean reduced operating costs, based on fewer unscheduled process shutdowns. Assuming a 5% savings in downtime due to enhanced reliability, the savings from this single benefit alone could almost repay the entire instrumentation program cost by the year 2010 (Figure 19). For this example, coal use projections and estimated downtime costs were taken from EPRI studies. (Improvements were assumed to affect all new capacity and to accumulate at 8% per year for existing capacity, beginning in 1985. Benefits were discounted at 12% per year.) Even greater savings could be realized through improvements in plant efficiency through better process control from the availability of more adequate instrumentation (Figure 20). If a conservative saving of 4% in operating costs is assumed as the average for all fossil energy conversion plants, the accumulated savings during the next generation of plant operation would be astounding.

SUMMARY

We must not make the error of underestimating the importance of future needs for instrumentation and control for fossil energy processes. Those of us who work in the energy technology area are so close to many of the problems, from an engineering and developmentery point of view, that we tend to lose sight of our real goal. Ultimately our purpose is to develop measurement and control systems that will provide an extremely high degree of confidence in the performance of a process. Making the process work is just a part of the problem. Our job will be finished when the process works so well that it will be accepted by the responsible members of the community in which it is to be installed. And, perhaps more important, some insurance underwriter will be willing to assume the liability risk at a reasonable cost to the operator. Without this degree of confidence, the necessary approvals and financing will be impossible to obtain. These processes will become practical, financial, and insurable only when we have done our task very well.

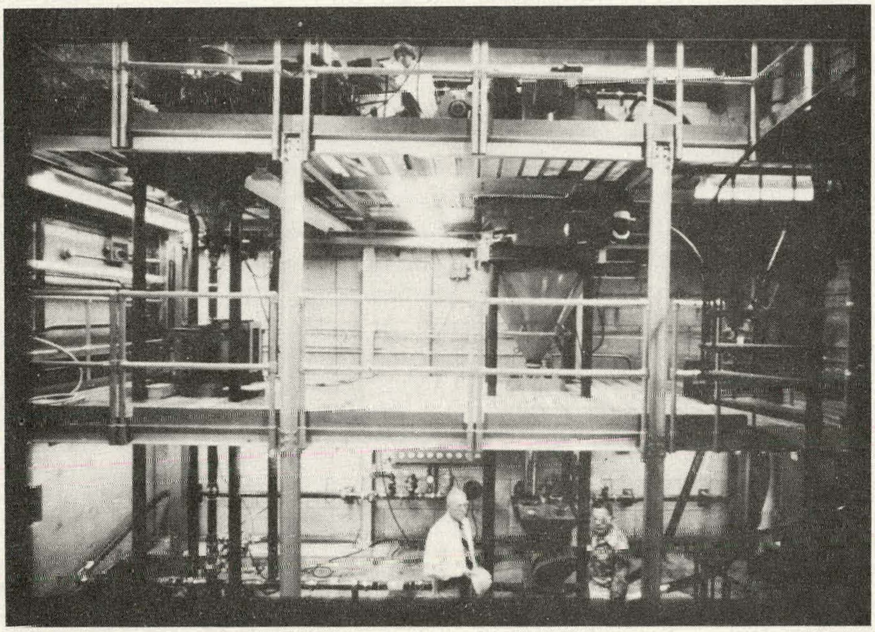


Figure 1 - Solid/Gas Mass Flow Instrument Test Facility

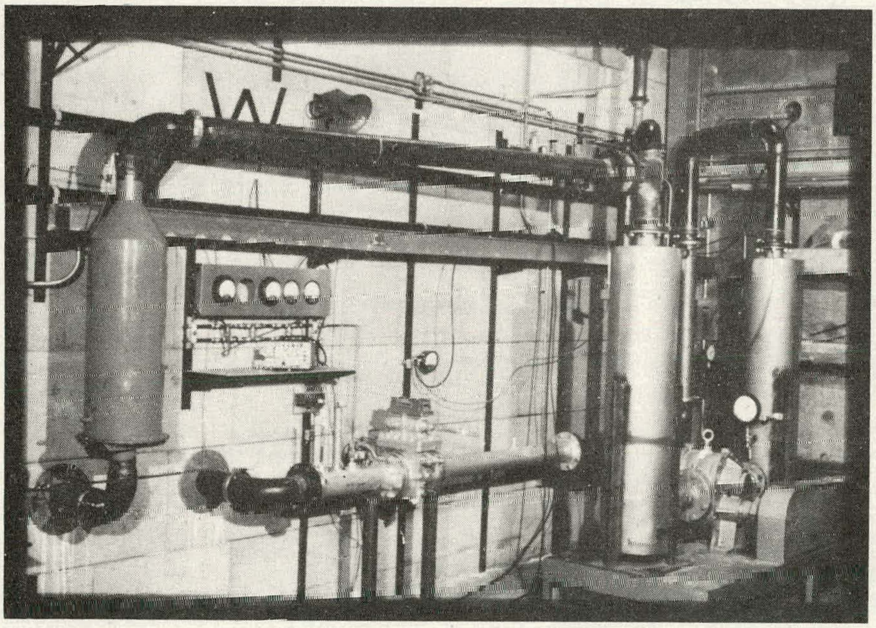


Figure 2 - Power Plant Section of Test Facility

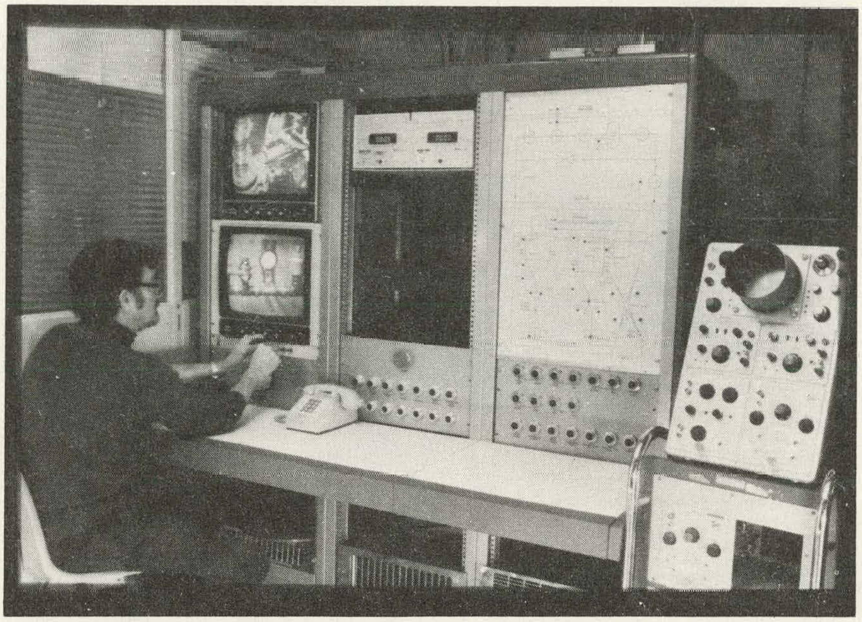


Figure 3 - Test Facility Instrumentation Panel

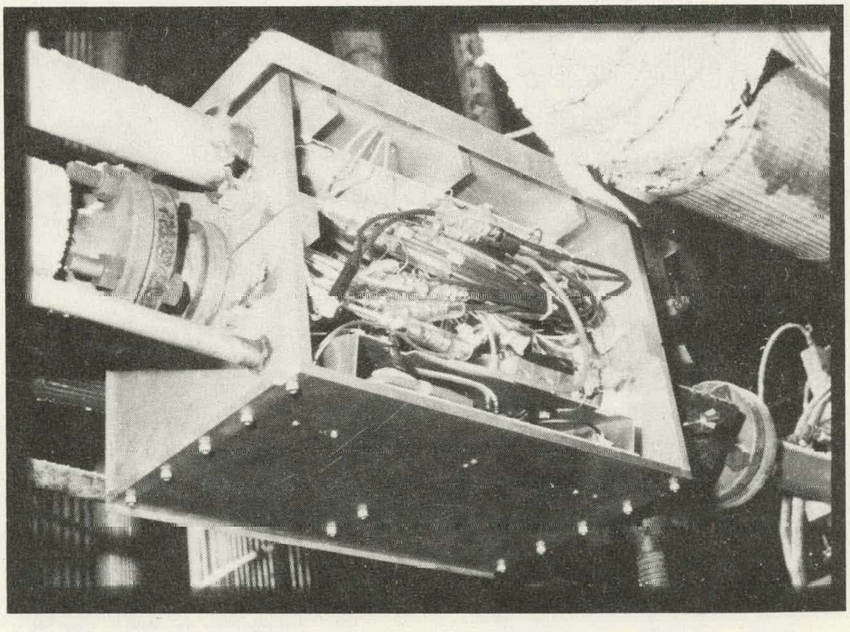


Figure 4 - ANL Capacitive Prototype Flow Instrument

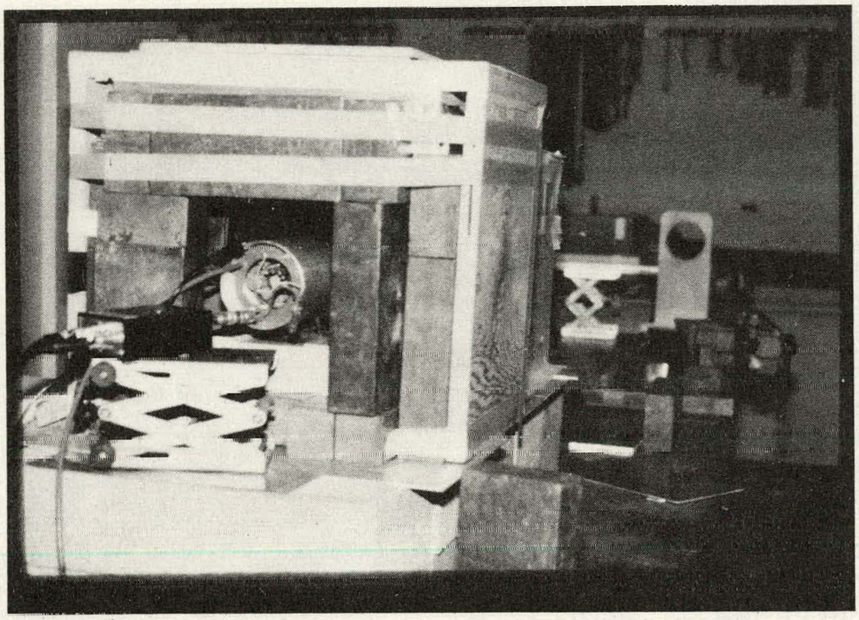


Figure 5 - Dual Gamma Ray Density Velocity Meter

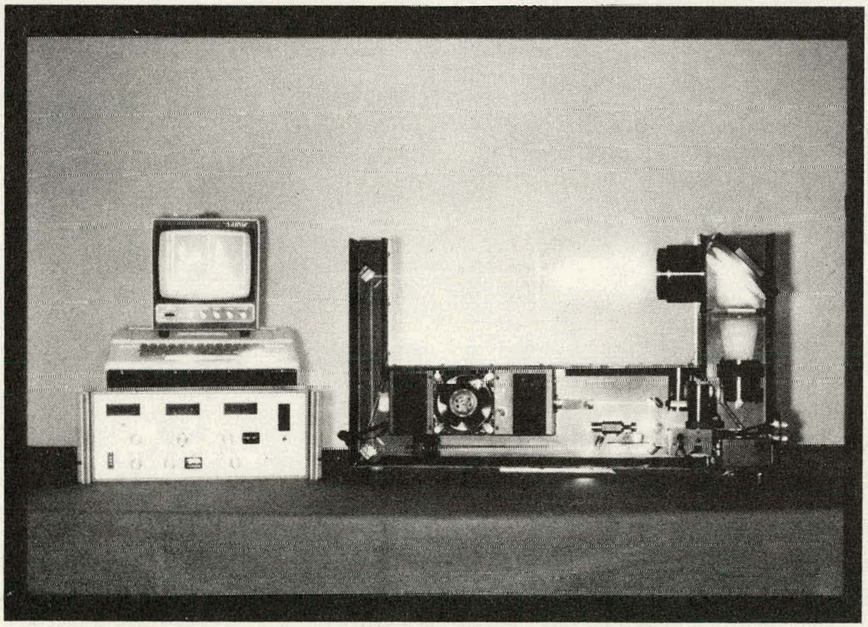


Figure 6 - SDL Optical Particulate Monitor System

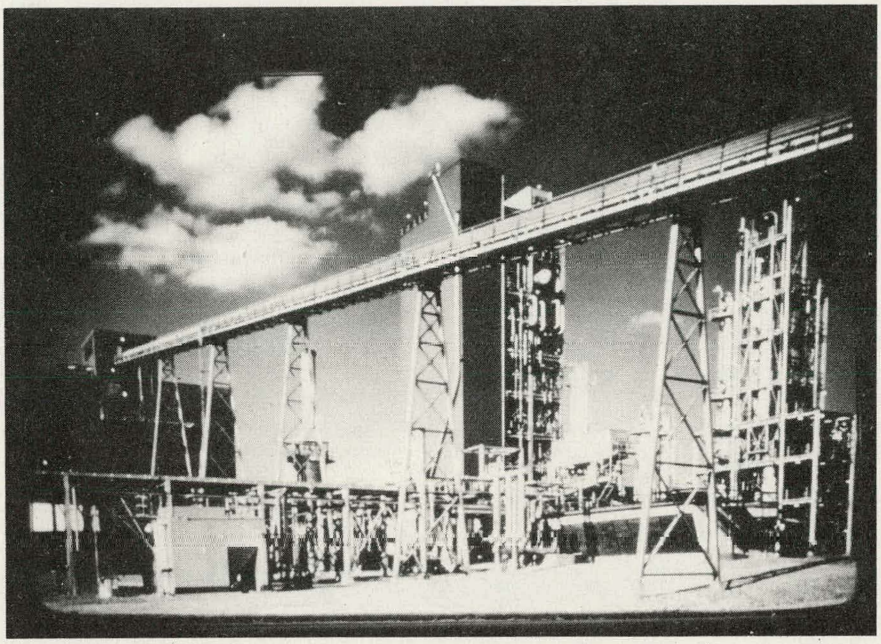


Figure 7 - Bi Gas Pilot Plant

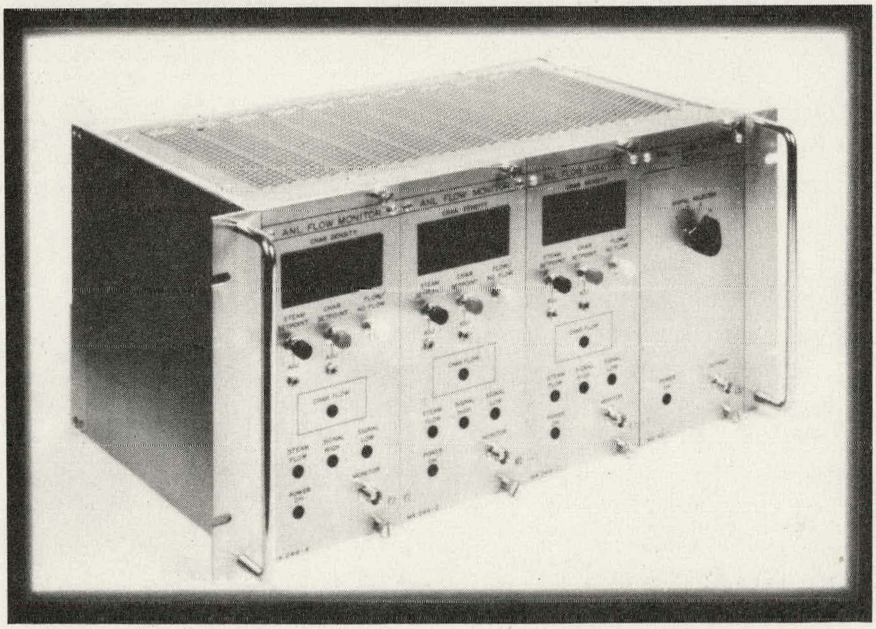


Figure 8 - Acoustic Flow/No-Flow Instrument Panel

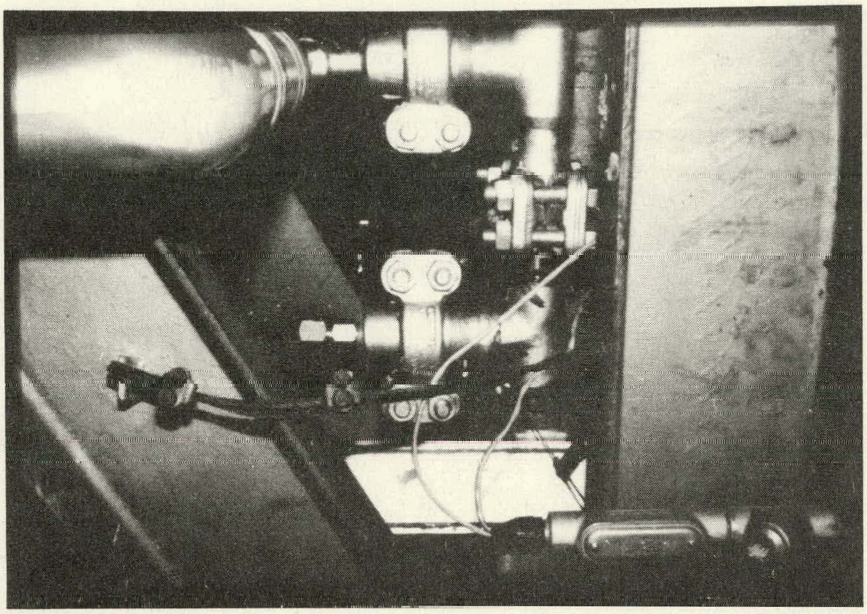


Figure 9 - Flow/No-Flow Meter Installation

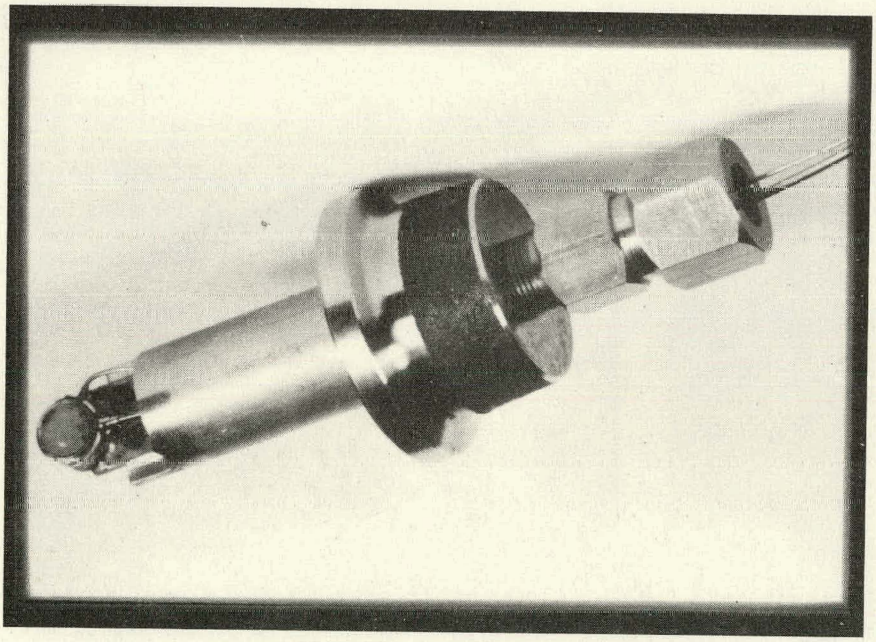


Figure 10 - Acoustic Sensor of Flow/No-Flow Meter

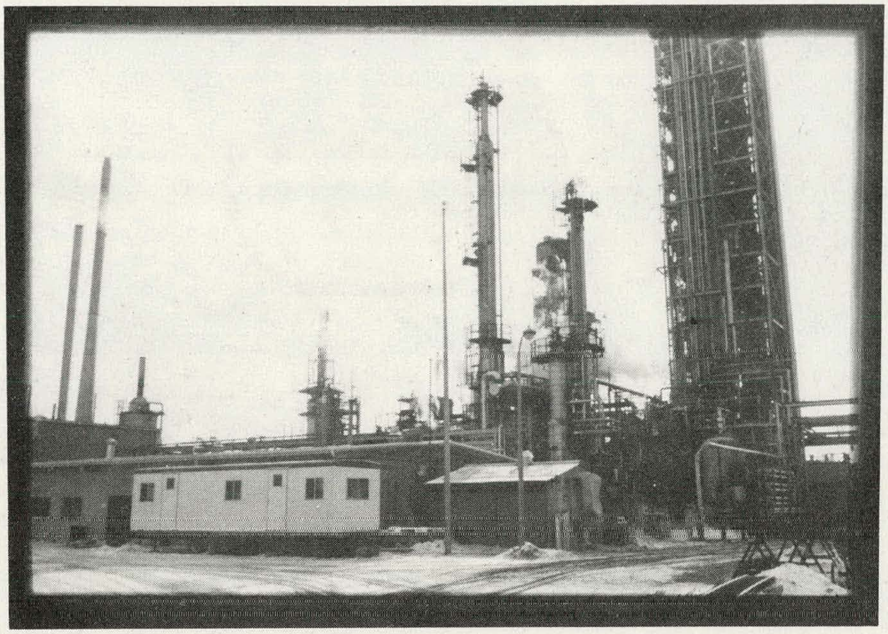


Figure 11 - HYGAS Pilot Plant

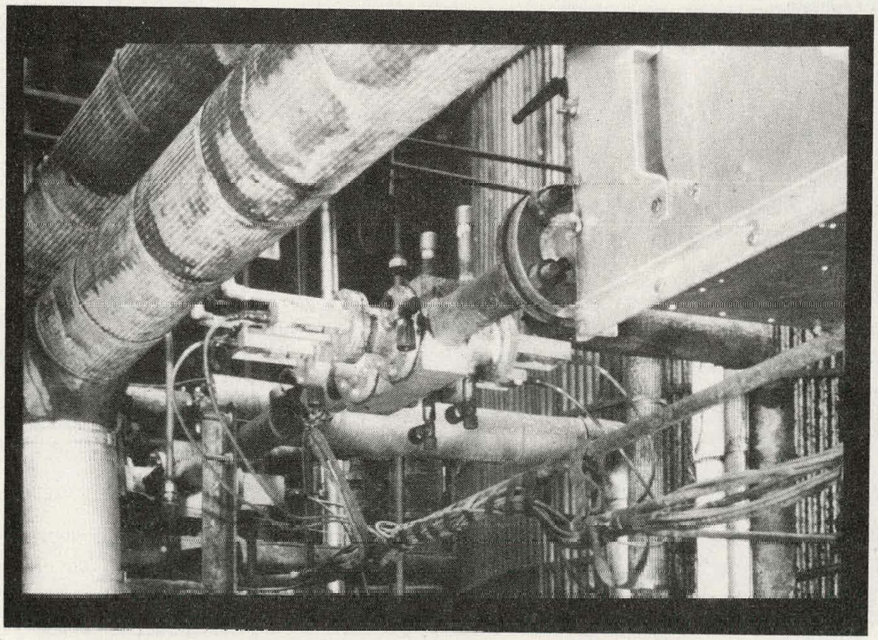


Figure 12 - Slurry Mass Flow Instrument Installation

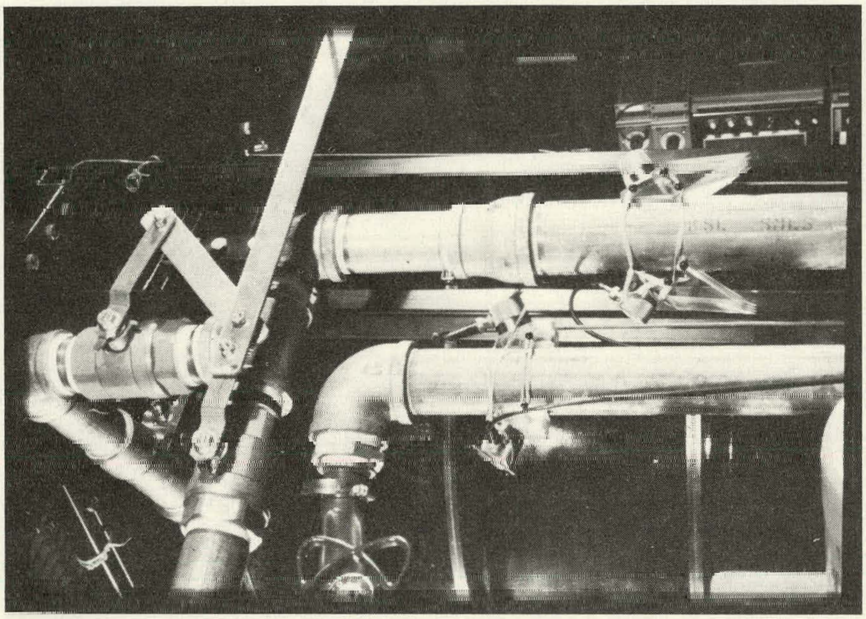


Figure 13 - Sonic Doppler Shift Flow Meter Installation

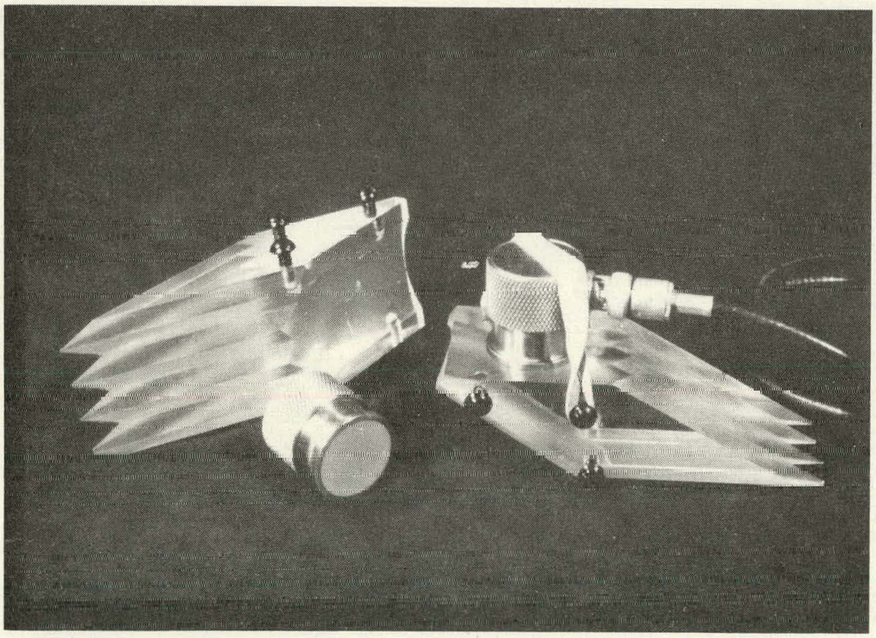


Figure 14 - Component of Doppler Shift Flow Meter

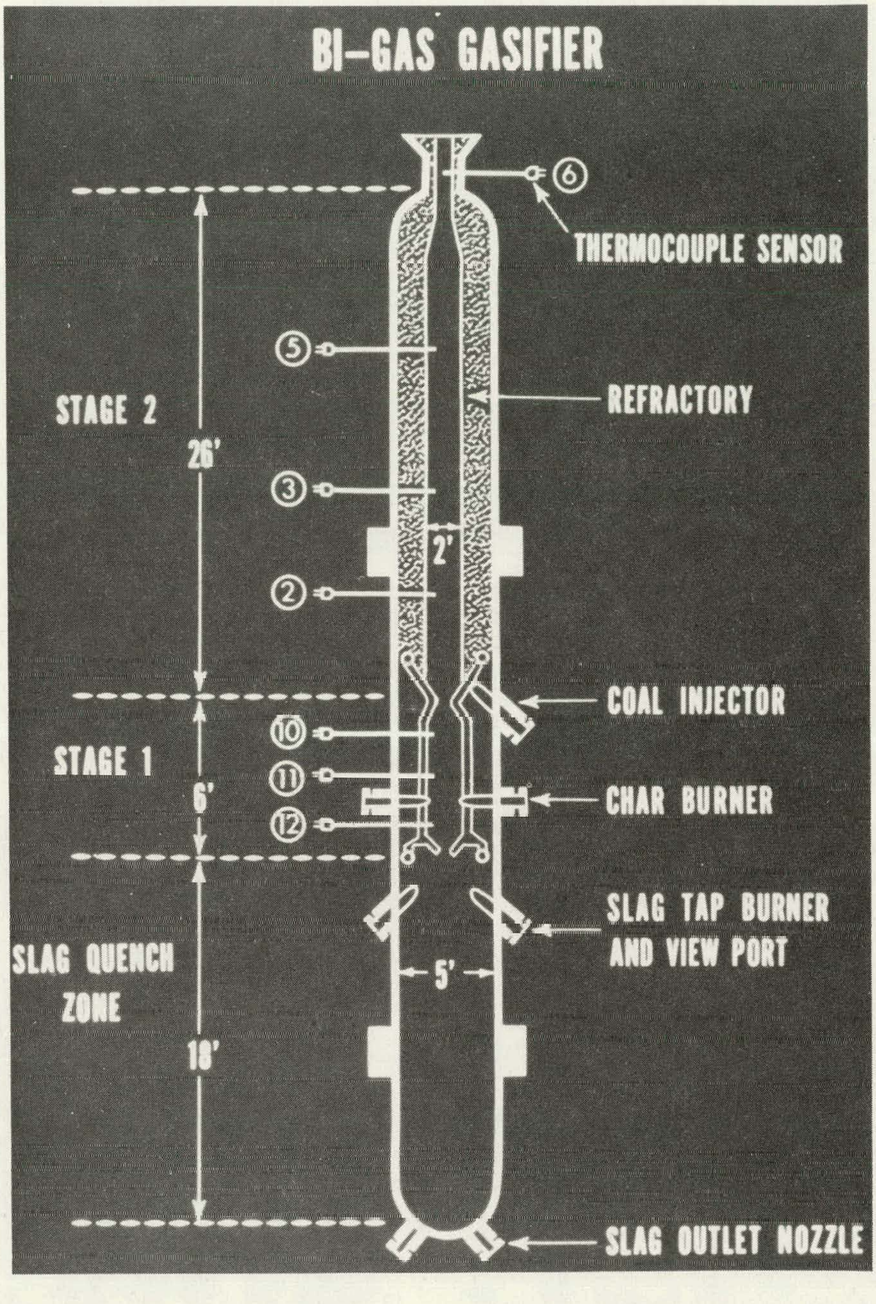


Figure 15 - Bi Gas Pilot Plant Reactor

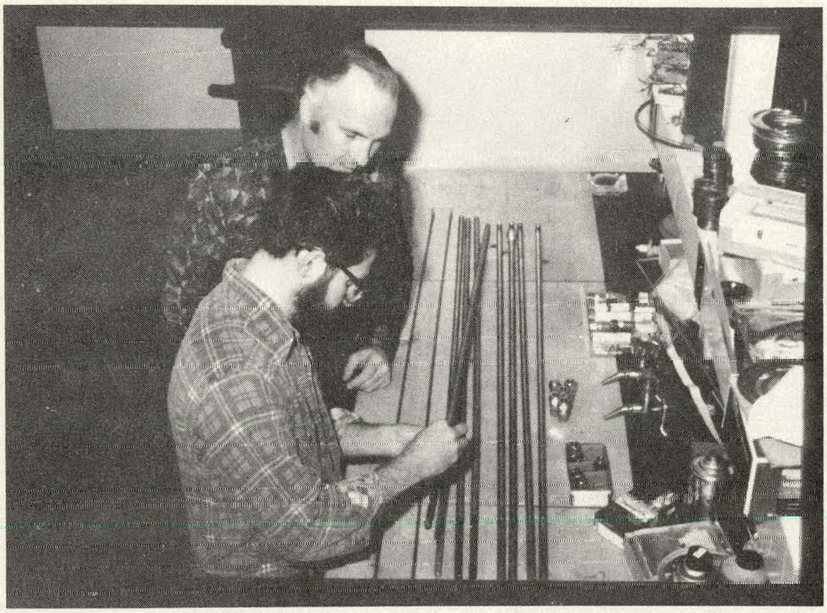


Figure 16 - Assembling Thermocouples

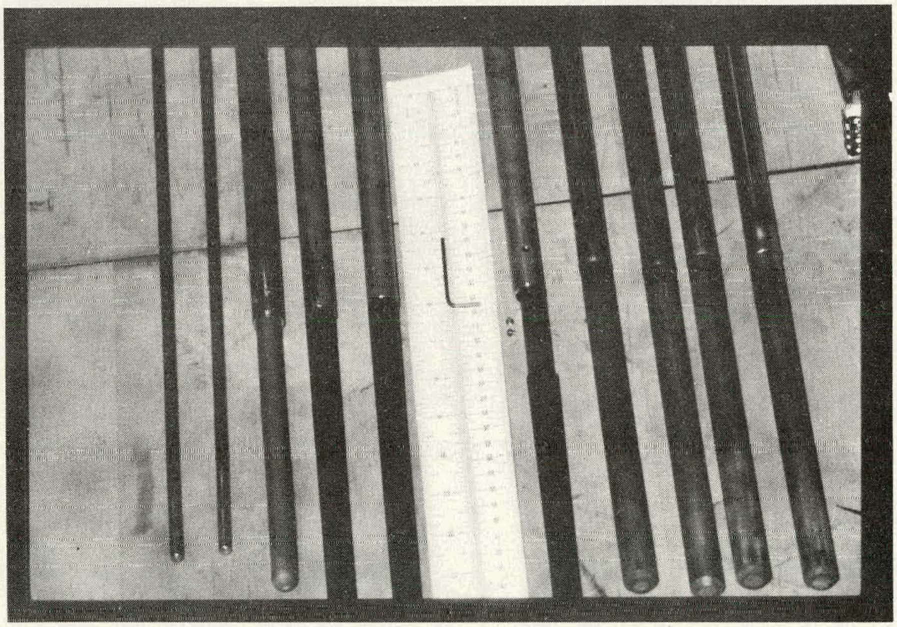


Figure 17 - High Temperature Thermocouples

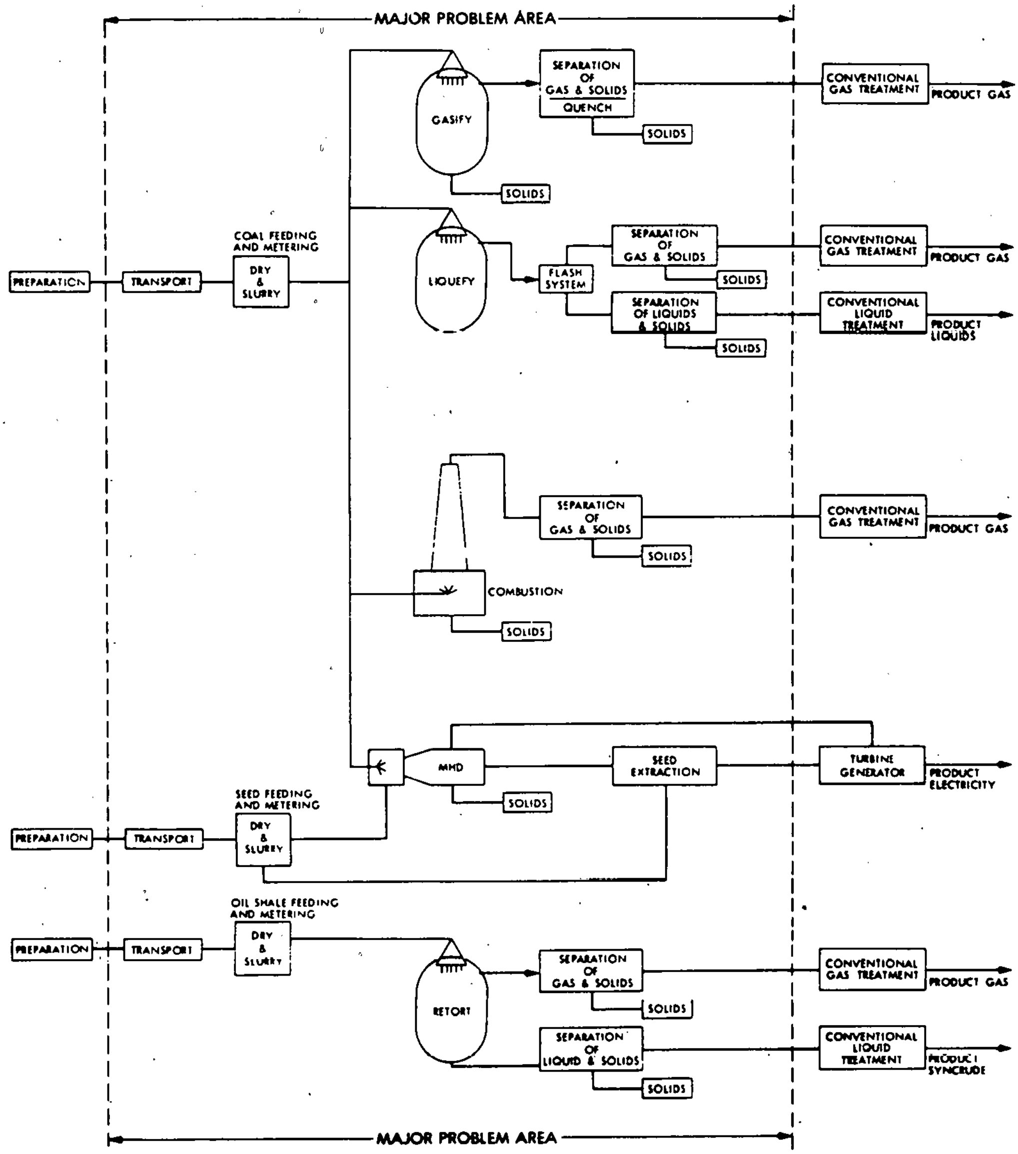


Figure 18 - Scope of I&C System Development Program

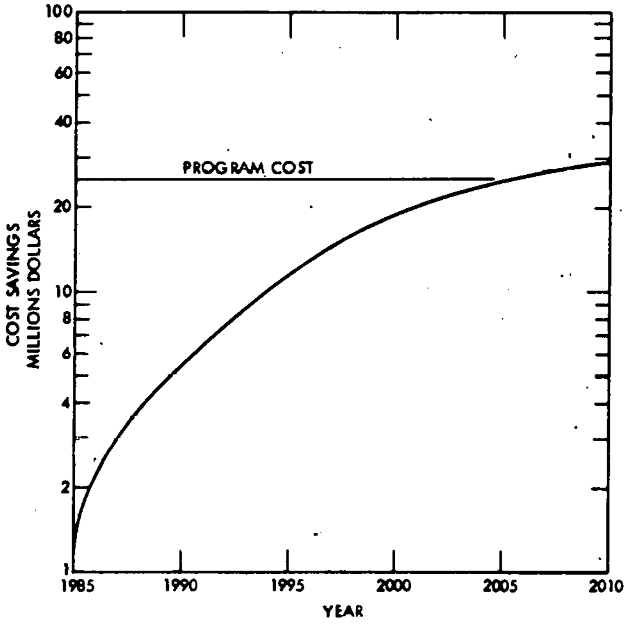


Figure 19 - Cost Saving from Increased Reliability/Reduced Downtime

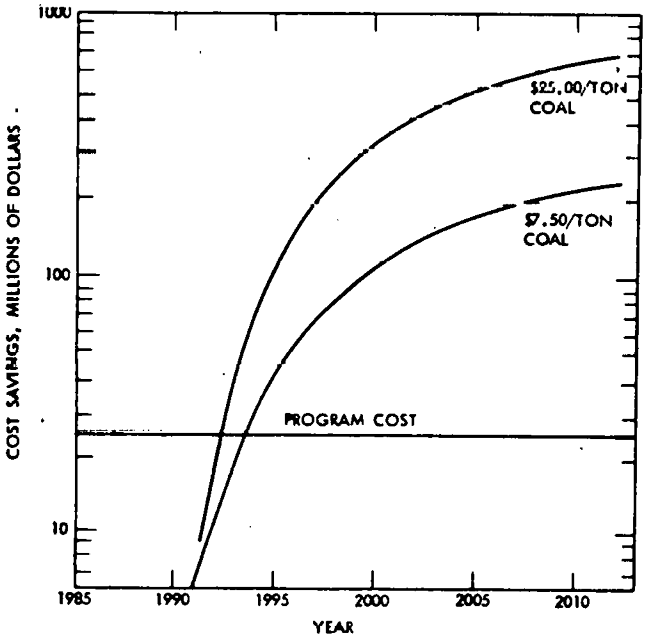


Figure 20 - Process Efficiency Improvement Cost Savings

INSTRUMENTATION PROBLEMS & POTENTIAL SOLUTIONS ASSOCIATED WITH THE SRC-II (SOLVENT REFINED COAL) PROJECT

David E. Rapley
Control Systems Engineering Manager

SRC-II Project
STEARNS-ROGER ENGINEERING CORP.

ABSTRACT

A 6,000 ton/day Coal Liquefaction Plant is being planned to demonstrate the feasibility of this technology. The plant will be comprised of several different processes which, due to their inherent characteristics, will require instrumentation that, is some areas, does not appear to be readily available.

This paper will examine some of the problem areas and the parameters that make their treatment difficult. In some areas potential solutions will also be presented.

The problems addressed will include but not be limited to the following:

High Pressure Slurry Flow Measurement
Letdown valves for High Pressure Slurry Service
Composition analysis for Recycle Slurry
Level/interface Detection Problems

INTRODUCTION

There are many reasons for presenting a "Paper". Probably the most common is for the dissemination of problem solution information. That is probably of secondary concern in this presentation.

One of our major difficulties during the past few years has been in keeping up with our rapidly developing technology. There are numerous development programs, which are both government and private industry funded. Becoming aware of and staying current with all relevant ones is very difficult. It was felt that this symposium would be an excellent forum to more widely publicize our problems. Hopefully it will also trigger a response from areas that we have not previously explored. This is the primary reason for presentation of this paper.

It should be pointed out that although the level of our efforts has been significantly different from one problem to another; nowhere in the area of instrumentation and measurement have we found anything that will prevent us from operating the plant. Also this paper does not address controllability of the overall complex or any unit thereof.

OVERVIEW OF SRC-II PROJECT

The SRC-II Project is a complex of some twenty or more highly interactive process units.

The facility is a demonstration plant for liquefying coal using the SRC-II process. The plant is designed to process 6700 tons per stream day (tpsd), of Pittsburgh seam coal. Principal products from the plant are low-sulfur fuel oil, pipeline-quality gas, liquefied propane and butane gases, and naphtha, as well as sulfur, ammonia and tar acid by-products. The heating value of the hydrocarbon products produced in the plant is approximately equivalent to the production from a 20,000 barrel per day petroleum refinery. Fig. I is a much simplified Block Diagram of the Project.

The primary processing sections consist of coal-slurry preparation, dissolver, refining, recycle gas treating and compression, hydrogen recovery and hydrodesulfurization. Other sections include hydrogen production, gas plants, and secondary recovery systems. The plant is designed as a grass-roots installation with utilities included except electric power which is purchased from a local utility.

The feed coal is pulverized and mixed with a recycle slurry stream from the process and then is pumped, together with hydrogen, through a preheater to a reactor or dissolver operated at high pressure and temperature. The coal is first dissolved in the liquid portion of the recycle slurry then is largely hydrocracked to liquids and gases. Much of the sulfur, oxygen, and nitrogen in the original coal is hydrogenated to H_2S, H_2O and NH_3 respectively. The rates of these reactions are increased by the catalytic activity of the undissolved mineral residues. Recycle of a portion of the product slurry contributes substantially to the process by increasing the concentration of catalytic mineral residue in the reactor.

The dissolver effluent is separated into gas, light hydrocarbon liquid and slurry streams using conventional flashing and fractionation techniques. A portion of the mineral residue slurry and hydrocarbon liquid from the separation area is recycled to blend with the feed coal in the slurry preparation plant. The balance of the mineral residue slurry is vacuum flashed to recovery the fuel oil product and the resulting heavy fraction is sent to gasification to produce hydrogen for the dissolver reaction.

The instrumentation problems so far encountered with the SRC-II Project are mainly in and around the dissolver area. They are due primarily to the high erosivity of the ash containing streams, combined with the high temperature requirements for the dissolver reaction and changing density of the slurry itself. The fact that the physical characteristics of the slurry are not as well-known as those of other more common fluids, also adds to the problems.

INSTRUMENTATION DESIGN PHILOSOPHY

Our approach has been to provide redundancy in any area that we are unsure of. In many ways this plant represents the first opportunity to demonstrate, under actual conditions, some of the instrumentation technology we envisage being required.

OVERVIEW OF PROBLEMS

Figure II is a chart of the problems that are being worked on, and should be referred to while following this part of the text.

Onstream composition analysis of these streams appears to be beyond current technology. However, an alternative to this in some places would be a reproducible percent solids measurement.

Moisture content of the coal is something we would like to measure but can operate without. Microwave and infrared techniques appear to hold some promise.

Ph measurement at 1990 psig and high temperatures may be a problem but more work is required to further define and clarify this.

A rapid analysis of Btu content at this point will be required. We are awaiting further definition before proceeding with any investigation.

The measurement of the slurry viscosity may be required at high temperatures. Reproductibility will be important but accuracy is still a desirable feature. Measurement of the viscosity of this erosive slurry in some places, may prove to be impractical with current technology but in these cases we will attempt to use a percent solids measurement as an indirect reading of viscosity.

The ability to be able to measure the flows of coal and recycle slurry, is one essential ingredient for successful control of the SRC-II process. These measurements must be repeatable and it is desirable that they also be accurate.

Pressures of 2000 psig and temperature of 800°F in the SRC-II process together with coking and/or caking effects of the slurry combine to create problems for instrumentation in slurry level measurement service. Capacitance probes and/or nuclear devices are being used in similar low pressure and temperature services. Differential pressure instruments are being used at higher temperatures/pressures.

Temperature measurement problems are anticipated by reason of one or more of the following phenomena - erosion, caking and coking. Temperatures measuring as high as 2800°F will be required in these hostile environments. Measurement of the Temperature profile in the dissolver itself (2850 psig) poses problems due to its H_2 environment and its effect on the thermocouple wire and sheath materials. Problems associated with physically locating the thermocouples where they are needed are also of concern. The dissolver vessel itself is very large with 12" thick walls.

Slurry letdown valves will be discussed at length later in this paper.

Lockhopper valves do not now appear to be a problem in the size ranges required. They are expensive but readily available, and acceptably reliable.

Pressure relief devices in slurry service are a very real problem. One of the main concerns is that of coking of the inlet to the device, thus preventing the device from operating. The use of rupture discs under the valves and/or purging will most likely alleviate this to some extent. It would be an understatement to say that, we anticipate that the passage of slurry fluids through a relief valve during overpressure conditions, will severely damage the valve internals. However, not all overpressures will result in passage of slurry fluids. During minor process upset relieving conditions, only gaseous fluids will be released and the valve can be expected to reseat.

DISCUSSION

Slurry Flow Measurement

As has been pointed out previously, the measurement of slurry flows is critical to successful control of the plant. Slurry flow must be measured at pressures of 2200 psig and high temperatures.

The pilot plant has operated in the past by estimating slurry preheater feed flow rates by the speed of the reciprocating charge pumps and "checking" this with a reading from a quadrant edged orifice plate/D.P. cell installation. Both of these methods are subject to inaccuracies due to erosion, etc.

However, with recent modifications the performance of the slurry flow meter has improved steadily. It has improved to a point where it is used for primary measurement and the pump reading is used to check its realiability. The meter, at the time of writing, had been in service for approximately eight months and is exhibiting no signs of wear.

The installation consists of a 6K stellite quadrant edged orifice plate. This is installed in a vertical line, with downward flow, and connected to a differential pressure transmitter via solvent purged impulse lines.

Calibration tests have been conducted that show that response is independent of Reynolds number and that the theoretical and actual flow coefficients are comparable. Recent tests suggest that accuracy of approximately two percent can be achieved. Further improvements are planned. In fact, a slurry flow metering test facility is planned and should be in service at the Fort Lewis pilot plant before the end of 1979. Plans include the testing of the following devices: elbow meter, segmental wedge, thermal flow meter, target meter, venturi tube and a mass flow meter, utilizing the coriolis acceleration principle.

There are other programs at places such as Argonne National Laboratories to develop other types of flow metering devices. Papers are being presented on some of these at this symposium.

PRESSURE LETDOWN, SAFETY RELIEF, LEVEL MEASUREMENT IN THE H.P. SLURRY LETDOWN SYSTEM

The Slurry Depressuring System is one of the most critical problems in the whole Project. In order to address all facets of the problem, the work in this area has been performed on a system basis involving a multi-discipline Team of Engineers.

In simple terms, the problem is one of reducing the High Pressure of the slurry in the dissolver effluent separator to that of approximately atmospheric. The ideal approach to this problem would seem to be the use of a power recovery device of some kind. Present technology does not permit this. In the absence of any other alternative we have selected an approach which is based on the use of Pressure Letdown Valves. This approach is illustrated in Fig. III. It is a three-stage Letdown System with the flexibility of operating with only two stages. The system can also operate with either a balanced or a constant pressure drop between each stage. There are three parallel valves per stage. These valves will be used consecutively to insure a reasonable run time, since Plant turnarounds are the only permissible time for maintenance to be performed. Adequate purging will be provided to prevent the slurry from plugging off lines that are not in service. Double block valves are provided upstream of the Letdown Valve, to provide tight shut off capability.

Letdown Valve Selection

An extensive survey of valve manufacturers has been made and a short list of promising candidates has been prepared. Vendor interest has ranged from "not interested"to one or two who are interested in designing a new valve for this service. The more common approach is to modify a standard valve design.

The best experience at the Fort Lewis Pilot Plant for this service has been with a Fisher angle valve using tungsten carbide trim. The maximum life achieved to date, is in the order of two months. However, trim breakage has been as big a problem as trim erosion. Some advantages are expected to be gained from the scale up from port sizes in the pilot plant of around 1/8" dia. to 1-1/2" to 2" dia. in the Demonstration Plant.

Another problem is that there is so little published data that can be used to accurately size valves for these conditions; and of course, an incorrectly sized valve is not conducive to optimum trim life.

At the time of writing, we are not aware of any facility, or any plans for a facility, where full size valves can be tested in this service.

Our plans are to leave the selection as late as possible, compatible with the project schedule. We will be continually encouraging and monitoring developments in this field; and at the predetermined point we will make a selection based on our opinion of what holds the most promise at that particular time. Certainly we will not restrict the selection to one type and/or vendor. This is too critical a service to have all of our eggs in one basket. Especially since we do not anticipate having a prior opportunity to run full scale tests as mentioned previously.

Materials of construction will also be selected at this late date. However if we had to decide today, our selection for materials would be stainless steel for valve bodies and tungsten carbide facing for the trim.

Level Measurement

Dual level devices will be provided for redundancy. We are presently considering purged differential pressure instruments and capacitance probes as holding the most promise. The purging of the D.P. cell is something that we would rather avoid and we are actively searching for alternatives. The thickness of the vessel wall precludes the use of nuclear devices.

Safety Relief Devices

Our approach to pressure relief protection is to provide a relief valve sized to satisfy A.S.M.E. codes requirements. This valve may be provided with a rupture disc, however, it is intended that this valve relieve only gaseous vapours resulting from minor upsets. Under these circumstances we can expect the valve to reseat. Alternate provisions must be allowed for the catastrophic over pressure which would result in passage of slurry fluids. It is expected that the passage of these slurry fluids at these differential pressures would completely erode the internals of a conventional relief valve. By also providing a valve similar in design and construction to the Letdown Valve, and set slightly below the conventional relief valve, we hope to minimize this effect.

SUMMARY

The Letdown System description above is a good example of our typical approach to the solution of instrumentation and measurement problems. In those cases where the problem/solution is determined to be beyond the state of the art, we are developing either practical alternatives for obtaining the required information or sources of alternative information that will still allow us to operate the plant.

Other examples of this would perhaps be slurry viscosity and % solids measurements. Both of these have been found to be beyond the current state of the art, due to fairly high process temperatures, solids particle sizes of up to 1/8" dia. and changing specific gravity.

It does appear, for some applications, that the readings from a true horsepower transmitter on the pump motor or mixer could be used. The torque required to drive the pump or mixer would be a function of the density of the slurry at a particular temperature. This then will enable us to operate the plant.

Many instrument readings are density dependent. Where this is a problem we may have to monitor density and compensate for any change. Depending on the rate of frequency of the change, the density readings may be obtained automatically or by laboratory analysis. With the use of the micro-processor based control system, the compensation can be easily effected.

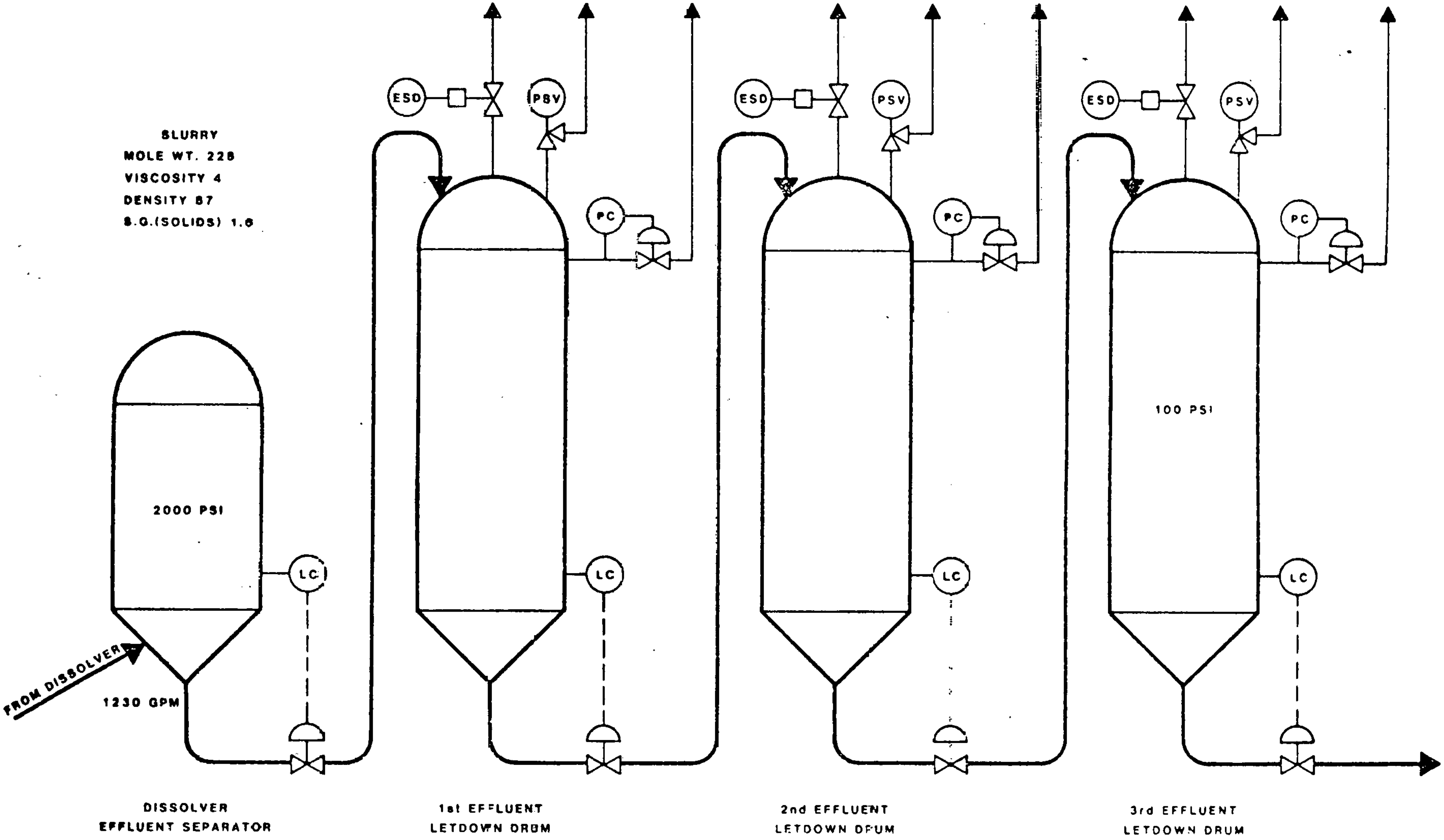
CONCLUSION

To date we have not identified any problem area that would prevent us from operating the plant. We have been able to either find a solution or an acceptable alternate arrangement. Our future plans are to continue our investigations into current technology and to work with establishments that are developing new technology.

The Author wishes to acknowledge the valuable contribution made by other members of the SRC-II Project Team in the preparation of this paper.

FIGURE III

SIMPLIFIED FLOW DIAGRAM HIGH PRESSURE SLURRY LETDOWN SYSTEM
SRC-II DEMONSTRATION PLANT



SOLIDS ARE FLY ASH, UNREACTED COAL, ETC., AVG. SIZE 10-50 MICRONS
MAX. 8 8''Ø HARDNESS - A LITTLE LESS THAN DIAMOND

FIGURE I
SIMPLIFIED SRC-II PROCESS
BLOCK FLOW DIAGRAM

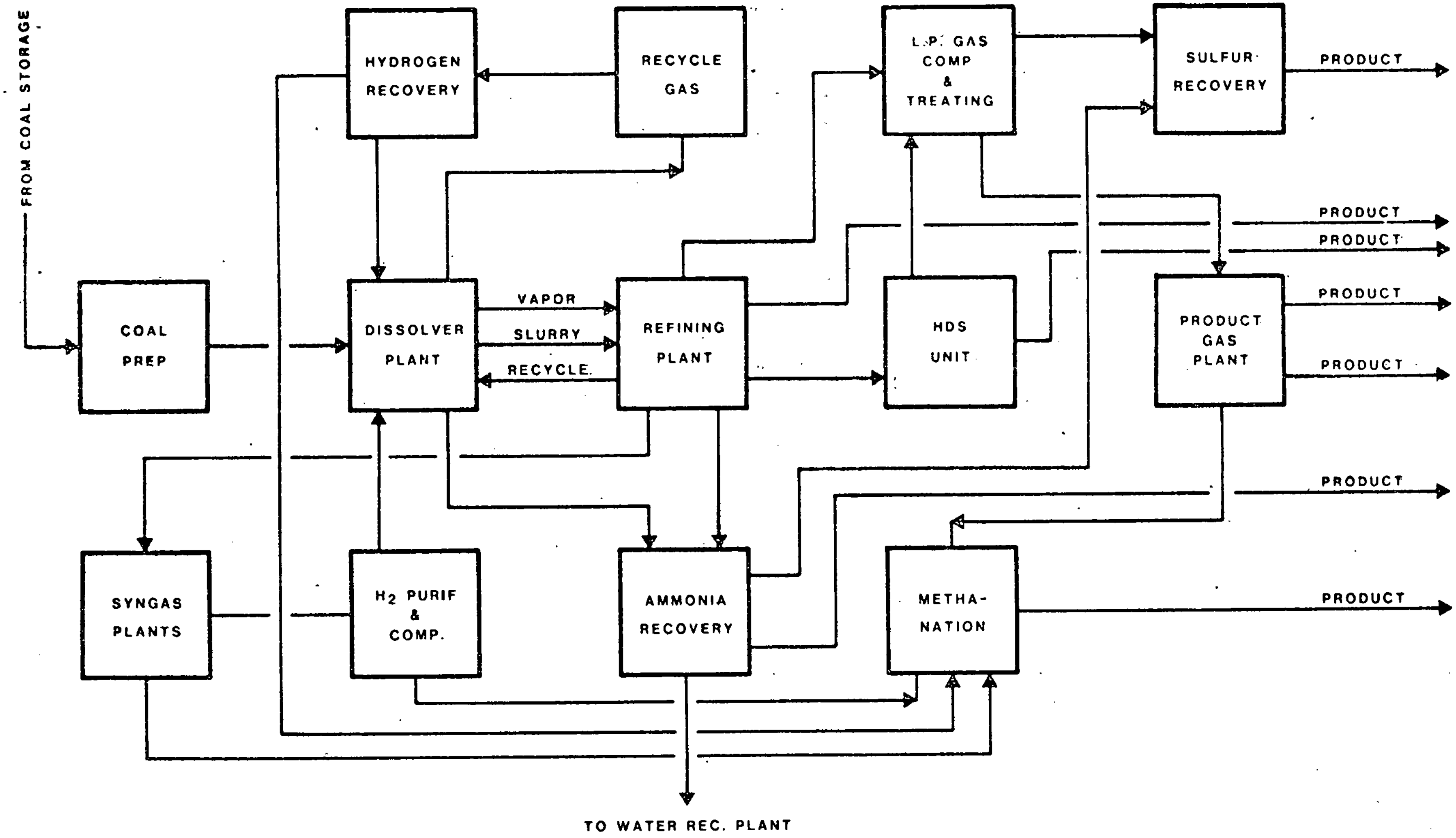


FIGURE II
POTENTIAL INSTRUMENTATION/MEASUREMENT PROBLEMS
SRC-II DEMO PLANT PROJECT

	COMPOSITION	MOISTURE	PH	BTU	VISCOSITY	%SOLIDS	FLOW	LEVEL	TEMP	LOCAL LEVEL INDICATION	H.P. SLURRY LETDOWN VALVES	LOCKHOPPER VALVES	PRESSURE RELIEF DEVICE
FEED TO PREHEATER	X					X	X						
RECYCLE SLURRY	X				X		X						
SYNGAS TO SHIFT CONV.	X			X			X						
FEED TO METHANATOR													
COAL FEED CONVEYOR	X	X											
HI-PRESS WASH SYSTEM			X					X		VESSELS IN SLURRY SERVICE			
SLURRY CHARGE TANK					X			X					
VAC. SL. BOTTOMS TO GASIFICATION							X						
DISSOLVER SEPARATOR								X					X
DISSOLVER L/D SEPARATOR								X			X		X
VACUUM DRUM								X					
GASIFIER QUENCH ZONE								X					
SLAG LOCKHOPPER								X				X	
PREHEATER									X				X
DISSOLVER									X				X
GASIFIER									X				
VAC. JUG LIQUID									X				

INSTRUMENTATION AND CONTROLS EXPERIENCE AT THE IGT U-GAS® PILOT PLANT

By

Amir Rehmat, Manu K. Vora, and William A. Sandstrom
Institute of Gas Technology
Chicago, Illinois 60616

ABSTRACT

At the Institute of Gas Technology (IGT), several coal and char gasification pilot plant programs to produce low-and medium-Btu gas have been successfully conducted during the last 6 years. The U-GAS® process consists of a single-stage fluidized-bed gasifier containing an ash agglomerator that achieves selective removal of high-ash-bearing material (agglomerates) and high carbon conversions. The three foot (0.91 m) diameter pilot plant reactor has produced quality medium-Btu gas at atmospheric pressure, over an operating temperature range of 1500°-1950°F (816°-1066°C).

This paper reviews the instrumentation techniques utilized for measurement and control of process variables for successful start-up, steady-state operation, and upset recovery in the U-GAS Pilot Plant. These variables include fluid bed level, density, temperature, pressure and process gas input and product gas flow rates. Emphasis is placed on the instrumentation and control methods pertaining to the gasifier (bed height, temperature and pressure), selective ash removal and elutriated fines reinjection. The need for additional control features on demonstration-scale plants is also stipulated.

To date, gasification tests have been successfully conducted using metallurgical coke breeze, bituminous coal chars, Montana subbituminous, Illinois No. 6, and washed and unwashed Western Kentucky No. 9 bituminous coals. U-GAS process tests have been completed to produce design data at 60 psia (413 kPa) for an Industrial Fuel Gas Demonstration Plant.

INTRODUCTION

The U-GAS process has been developed by the Institute of Gas Technology (IGT) to produce low- and medium-Btu (150-300 Btu/SCF, 5588 to 11,175 kJ/m^3) fuel gas from coal that when burned does not need a stack gas cleanup system (1-6). This gas can be used for industrial heat furnances, process steam boilers, in electricity generation in combined-cycle power plants, and in industrial parks as a local substitute for natural gas. It can also be converted to a chemical feedstock for production of hydrogen, ammonia, alcohol or methane (SNG).

The U-GAS process converts more than 90% of the carbon and hydrogen in the feedstocks to a medium-Btu gas. In fact, the U-GAS process accomplishes four important functions in a single stage; it handles caking coal, devolatalizes and gasifies the coal and agglomerates the ash from the fluid bed. Other characteristics of the process include the capability to gasify all ranks of coal, and to process crushed coal including the fines. The process has a simple design which provides a reliable, controllable operation able to withstand upsets. The product gas is significantly low in tar and is environmentally acceptable with a minimum of treatment.

This paper briefly describes the principal features of the U-GAS process and discusses the instrumentation techniques utilized for measurement and control of this important synthetic fuel process.

U-GAS PROCESS DESCRIPTION

In the U-GAS process, coal, generally 1/4 inch X 0, is surface dried for handling purposes and pneumatically injected into the gasifier through a lockhopper scale system. Within the fluidized bed, coal reacts with steam and oxygen (air can be substituted for oxygen) at temperatures of 1750° to $1900^{\circ}F$ (954° to $1038^{\circ}C$). The temperature of the fluid bed depends on the type of coal feed and is controlled to achieve ash agglomeration (not slagging) conditions. The operating pressure of the process depends on the ultimate use of the product gas and may vary between 50 to 350 psi (345 to 2412 kPa). The pressure must be optimized for a particular system; for production of an industrial fuel, a minimum pressure of 80 to 100 psi (551 to 689 kPa) is desirable. At the specified conditions, coal is gasified rapidly, producing a gaseous mixture of hydrogen, carbon monoxide, carbon dioxide, and a smaller fraction of methane. Because reducing conditions are always maintained in the bed, most of the sulfur present in the coal is converted to hydrogen sulfide.

Simultaneously with coal gasification, the ash is agglomerated into nearly spherical particles and separates from the bed. Part of the fluidizing gas enters the gasifier through a grid. The remaining gas flows upward through the ash agglomerating device and forms a flame zone within the fluidized bed, where the temperature is greater than at other locations in the bed. High ash content particles agglomerate under this condition, grow larger and heavier until they are selectively separated and discharged from the bed. They are withdrawn at the ash hoppers. In this manner, this fluidized-bed reactor achieves the same low level of carbon loss in the discharge ash as is generally associated with the ash-slagging type gasifiers.

Coal char fines elutriated from the fluidized bed are collected in two external cyclones. Fines from the first cyclone are returned to the bed, and fines from the second cyclone are returned to the ash agglomerating flame zone, where they are gasified, agglomerated with bed ash, and discharged as ash agglomerates. The raw product gas is significantly free of tar and oils, and thus the ensuing heat recovery and purification steps dictated by the end use of the product gas are simplified.

DESCRIPTION OF THE PILOT PLANT

The U-GAS pilot plant is located at IGT's test facility in southwest Chicago along with the HYGAS® pilot plant. The U-GAS facility consists of a gasifier and all required peripheral equipment, most of which is contained in an enclosed structure about 100-feet high (30.5 m).

The U-GAS equipment includes a feed drying and screening system with storage silos, a lockhopper system (weighed) for feeding a dry crushed material at rates up to 3000 lb/hr (1364 kg/hr). The refractory-lined fluidized-bed gasifier reactor has a special agglomerate withdrawal system in its base. Downstream is a product gas quench system, a cyclone system for removal and recycle of elutriated fines, a product gas scrubber and a product gas incinerator.

The pilot plant flow sheet is shown in Figure 1. The 3-foot (.91 m) diameter by 25-foot (7.62 m) high reactor has a 4-foot (1.22 m) diameter freeboard. The reactor is lined with high alumina and insulating refractory to reduce the wall temperature to 230°F (110°C) and minimize

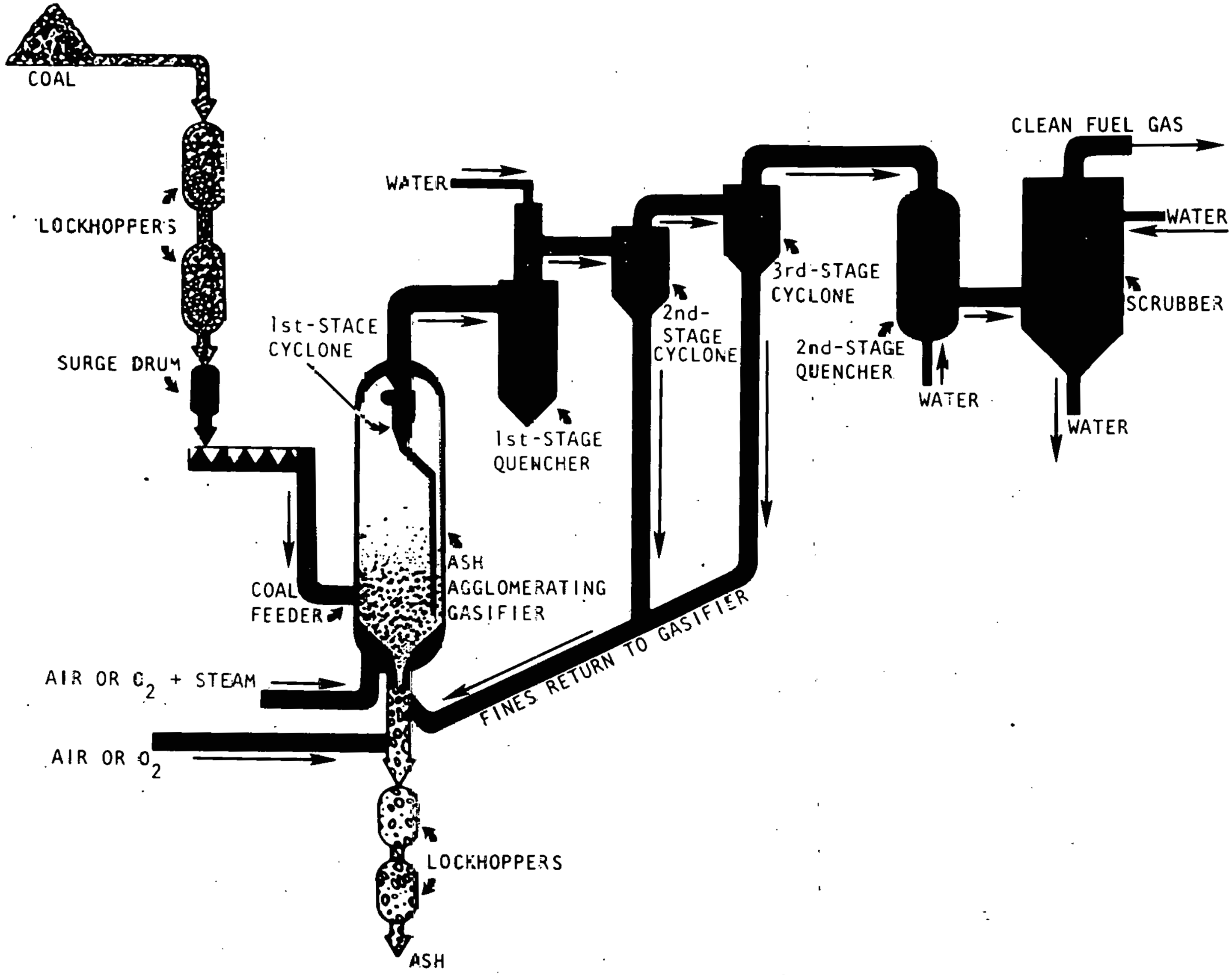


Figure 1. FLOW DIAGRAM OF THE U-GAS PILOT PLANT

heat losses.

Pilot plant process instrumentation records fluidized-bed density and height along with all process gas flow rates. Temperatures are recorded for all process and product gas streams as well as numerous locations within the fluidized-bed reactor. The product gas composition is continuously monitored by infrared, thermal conductivity, and paramagnetic instrumentation. These gas composition monitors are checked by mass spectrometer analysis of samples. All solids streams are frequently sampled and analyzed for carbon, ash, sulfur, volatile matter, and particle size range. The ash agglomerates that are discharged through lockhoppers are weighed, and sampled. Elutriated fines (when not recycled to the process) are also weighed and sampled as they are removed.

The pilot plant feed system includes several transfer conveyors, 80-ton (72.7 Mg) and 100-ton (90.9 Mg) silos (with 5-ton [4.5 Mg] internal storage hoppers) and two 11-cubic foot (0.31 m^3) lockhoppers. One of the lockhoppers provides surge storage for the reactor feeder. The lockhoppers are part of an automatic batch weight system. This system keeps the reactor screw feeder filled, and each weigh dump is recorded in the control room. The solids are regulated by a screw feeder supplying a pneumatic system that injects the feed directly into the gasifier.

The product gas leaving the reactor enters the first stage quencher where it is direct cooled to about $1000^{\circ}F$ ($538^{\circ}C$) by a stream of water atomized by nitrogen. Two cyclones located downstream of this quencher, return fines to the reactor. These cyclones are upstream of a second quencher, where gas is cooled to $500^{\circ}F$ ($260^{\circ}C$) before it is sent to a gas scrubber. The scrubbed gas is then burned in an incinerator.

INSTRUMENTATION

Proper operation of the U-GAS pilot plant is maintained by monitoring solids streams through sampling and the use of temperature and pressure measuring devices. Periodic bed sample analyses are used to control the accumulation of ash in the bed, and minimize the carbon loss when char is discharged with the ash.

The following sections describe the instrumentation developed to operate the U-GAS pilot plant and discusses specific instrumentation techniques utilized to control improtant process parameters.

Instrumentation of The U-GAS Pilot Plant

The majority of U-GAS pilot plant instrumentation is standard process industry equipment adapted to measure and control the operation of the process. Basically, the pilot plant is equipped with a pneumatically operated, closed-loop feadback, automatic control system. Basic process variables measured and controlled are fluid-bed level and density, reactor pressure, temperature and flow rate of the gasification media. The application of this instrumentation to the U-GAS process is discussed below.

Density

The density of the U-GAS fluidized bed and the incipiently fluidized fines in the cyclone diplegs is measured. This information is needed to determine the reactor fluidized-bed height and assure efficient operation of the cyclones. The technique of hydrostatic head measurement has been employed with good reliability.

The hydrostatic head principle interprets density by a differential pressure measured over a specific height of fluid. The simple equation of $\rho = P/h$ (where ρ = density, P = pressure, and h = height) is used to calculate the density.

Level

Because the U-GAS process utilizes a fluidized-bed for solid-gas contacting and heat transfer, accurate bed height or volume measurement is necessary to control product gas quality. The method used for indicating fluidized-bed levels utilizes the differential pressure between two pressure taps. A low pressure tap is located above the fluid-bed level and a high pressure tap at the bottom of the bed, and this latter tap is also connected to another fluidized density transmitter. This other transmitter's low pressure tap is located in the bed and at a specified distance above the combined tap. The pressure differential of this latter transmitter establishes the bed density and is used to determine the true bed height by correlation with the pressure differential of the first transmitter.

Measurement of the U-Gas reactor's fluidized-bed levels is reliable only if nitrogen gas purges are used for the pressure-sensing lines of the d/p cell transmitters. These purges are necessary to prevent solids and/or condensible gases from accumulating and plugging the pressure taps. Accurate and stable purge flow control is necessary to achieve accurate bed level recordings.

Naturally, zeroing and spanning of transmitters must be conducted when purges are on to offset error in readings. Similarly, purge meter flow control is best achieved if the regulating valve is located downstream of the purge meter. The plugging of pressure tap lines is greatly minimized if the purge meter pressure is 25% or more above tap pressure. As the U-GAS process operates at low pressure, purge gas density pressure head can be neglected as an effect upon transmitter zero at reactor operating conditions.

Besides fluidized-bed level measurements, U-GAS instrumentation must indicate bulk solids level in the lockhoppers. An electronic vibrating sensor (Dynatrol) has been found to be accurate and reliable for providing level indication for coal, coke ash, char fines and ash displaced in water.

Flow

Accurate flow measurement and control of U-GAS process gas and water streams is essential for material and energy balances to be calculated from pilot plant data. These flow measurements are obtained through conventional "head"-type meter installations where the differential pressure is measured across a primary element to indicate a flow rate. Common concentric, sharp-edge orifice plates are used as primary elements to obtain flow rates for these homogeneous fluids. Solids flows are obtained by periodically weighing materials fed to or discharged from the system.

Pressure

Pressure detection and control has presented no serious problem at the U-GAS pilot plant. To measure reactor or product gas pressure, sensing lines are purged and the pressure of the purge gas is measured by gauge or pressure transmitter. No purge is used where there are no solids in the medium to be measured.

Temperature

Accurate measurement and control of bed temperature is essential to successful operation of the U-GAS reactor. Some critical considerations in temperature control include eliminating set point over-shoot; locating thermal elements in representative areas; and obtaining fast, accurate sensor response. The pilot plant is temperature controlled by manual adjustment of process reactant (oxygen and steam) input flow rates. A larger plant would require automatic control of these inputs.

Temperature measurement in the U-GAS pilot plant is accomplished by conventional thermometry techniques. Chromel-alumel, Type K, thermocouple junctions are used exclusively for measuring temperatures up to 2400°F (1316°C). A few Type J, thermocouple junctions measure temperatures below 1000°F (538°C). Sheathed, ceramic, insulated-type thermocouples are used for Type K. They are installed in 310 stainless steel thermowells for protection from the abrasive and corrosive environments found in the process. Iron-chrome or ceramic sheathed thermowells would probably be preferred for longer service life.

Instrument Monitoring of Process Control Parameters

Fluidization Stability

The most critical area in the entire system is the gasifier fluid bed itself. By nature the U-GAS process yields a segregated fluid bed. It was necessary to develop and or apply instrumentation to monitor different zones of the fluid bed to assure that each section was adequately fluidized. Monitoring is achieved by measuring a pressure drop across differential heights of the fluidized bed. A significant increase in pressure drop in the lower section is an indication of heavy ash accumulation that should be removed by gas flow adjustment at the ash removal venturi line. Both temperature and pressure recorders are quite useful to detect defluidization. A sudden reduction in recorded pressure or an excursion in the bed temperature, after the reactor bed has attained a steady-state, is an indication of defluidization and clinker formation. However, a bed temperature indicator is not 100% reliable since clinker formation may be localized and not take place near a thermal sensing element and thereby furnish no alarm. A sudden change in pressure drop across the bed at stabilized temperatures and flows, is a more certain indication of defluidization and clinker formation. Whether the general level of the pressure signal rises or falls is not as important as a decrease in the magnitude of the signal fluctuation chart trace. The latter state is almost a sure sign of defluidization and clinkering.

Fluidized-Bed Density

The density of the fluid bed is obtained by measuring the pressure drop across a known vertical distance in the fluidized bed. This density has been found to be directly related to the amount of ash present in the gasifier bed and can be utilized to control the bed ash content. An excessive amount of agglomerated ash present in the fluid bed can cause defluidization if it is not removed by adjustments in the solids classifying process gas flow.

At the U-GAS pilot plant, the ash agglomerates can be discharged at a controlled rate by manual operation of the solids classifying process gas flowing up the ash discharge throat. This manual method is not suitable for large or demonstration scale plants. Large plants will require automatic ash discharge control, utilizing the relationship between the bed ash content and bed density as the control parameter for maintaining constant ash levels in the bed. Upon an increase in density above that desired, a reduction in the flow of solids classifying process gas entering the ash discharge throat would permit smaller particulate size fractions of ash to discharge from the bed and thereby reduce bed density.

A backup pressure differential detector system should be employed to provide a method to detect an increase in bed ash concentration that does not yield an increase in bed density. If no bed density difference exists throughout the height of the fluid bed then ash agglomerates are not forming as gasification proceeds. A preset differential pressure alarm could be employed that would trip automatically if the differential pressure indicators did not show a higher density at the bottom of the fluid bed. This alarm would be used by operation personnel to alter operating conditions to prevent bed defluidization.

Fluidized-Bed Temperature

The control of fluid-bed temperature is essential for sustaining steady-state ash agglomeration. This temperature can be easily controlled by adjusting the rate of oxygen input. The U-GAS process system incorporates a process gas jet line through which oxygen-steam or air-stream mixtures can be controlled automatically. A bed temperature controller thereby should be used to adjust this flow of oxidant to maintain the temperature set point. Naturally, this flow would be automatically cut off in the event of a high temperature excursion.

Rate of Ash Discharge

The steady discharge of ash agglomerates through the ash throat is essential to continuous clinker-free operation. A plugged throat will cause local defluidization on the grid and significant clinker formation. By monitoring the pressure drop across the ash throat, early evidence of local defluidization can be detected. A significant reduction or rise in the throat pressure drop is a very definite indication of a plug in this line.

The temperature in the ash discharge line can also be used to classify ash from char so as to minimize carbon loss. When the ash discharge material is high in carbon content, this carbon ignites as the solids pass through the classifying process gas. The rise in line temperature generated is proportional to the carbon content of the falling solids. Accordingly, this ash discharge line temperature combined with periodic ash analysis of the falling solids can also be used to control the flow rate of the ash classifying gas.

Coal Feed and Fines Return Rate Stability

The flow of coal feed into the reactor and the fines return from the cyclone are also monitored through the change in pressure drop in their feed/return lines. These pressure drops are measured between the bed and a point on the feed/return lines. Pressure differential alarms can provide an early warning of process feed and fines recycle instability which can then be corrected.

Thus differential pressure and specific temperature relationships have been widely employed or noted as quite useful to the U-GAS process for control as well as monitoring to assure operating stability.

U-GAS DEMONSTRATION PLANT

Memphis Light, Gas and Water (MLGW) Division of the City of Memphis, Tennessee, entered into a contract with the U. S. Department of Energy (DOE) in late 1977 for the design and construction of an Industrial Fuel Gas (IFG) Demonstration Plant. MLGW has entered into sub-contracts with IGT, Foster Wheeler Energy Corporation, and Delta Refining Company to achieve design, construction, and operation of the Demonstration Plant. These four companies comprise the industrial team. MLGW's contract calls for utilizing the IGT U-GAS process to produce 175 million cubic feet (5 million cubic meters) of medium-Btu fuel gas per day (284 Btu/SCF-10579 kJ/m^3) from Western Kentucky #9 coal (2800 tons/day-2545.5 Mg/day). This industrial fuel gas will be produced and delivered to industrial customers in the Memphis area.

The entire program will be conducted in three phases (7). Phase 1 includes pilot plant gasification tests by IGT to provide specific data on Western Kentucky coal for the preliminary design of the Demonstration Plant. Phase 2 covers the engineering, design and demonstration plant construction. Phase 3, testing and operation of the demonstration plant, is to be completed by 1985.

The process control system for the Demonstration Plant will draw on the control principles developed in the pilot plant. Automatic control of the fluid-bed level (through feed rate control), the bed temperature (through steam and/or oxygen flow control), and the ash discharge rate (through bed density control) will be required. Load following can be accomplished through control of fluidization velocity and operating pressure.

CONCLUSION

Present day control technology has been successfully applied at the

U-GAS pilot plant. These techniques have been adapted to monitor as well as control the critical aspects of the process, namely temperature, pressure, bed density and height, ash discharge rate and the elimination of sinter formation.

The same principles will be utilized in the development of the U-GAS demonstration plant, however, the instruments to achieve the same goal may be selected with more advanced concepts to offer a combination of performance, operating features, flexibility, maintainability and dependability.

ACKNOWLEDGEMENTS

The information required to prepare this paper has been obtained from work conducted at the IGT U-GAS pilot plant under the sponsorship of the United States Department of Energy (DOE) and Memphis Light, Gas and Water (MLGW) Division of the City of Memphis, Tennessee.

REFERENCES

1. Sandstrom, W. A., Rehmat, A. G., and Bair, W. G., "The Gasification of Coal Chars in a Fluidized-Bed-Ash Agglomeration Gasifier," Paper presented at the 69th Annual AIChE Meeting, Chicago, November 1976.

2. Rehmat, A., Vora, M. K., and Sandstrom, W. A., "Low-Btu Gas from the IGT Ash-Agglomeration Gasification Process," Paper presented at the 13th Intersociety Energy Conversion Engineering Conference, San Diego, August 20-25, 1978.

3. Sandstrom, W. A., Vora M. K., and Rehmat, A. G., "IGT U-GAS Pilot Plant: High Temperature Fluidization," Paper presented at the 71st Annual AIChE Meeting, Miami, November 12-16, 1978.

4. Patel, J. G., "U-GAS Technology Status," Paper presented at the Symposium on Advances in Coal Utilization Technology, Louisville, Ky., May 14-18, 1979.

5. Vora, M. K., Sandstrom, W. A., and Rehmat, A. G., "Ash Agglomeration in Fluidized Bed Coal Gasification," Paper presented at the Sixth National Conference on Energy and the Environment, Pittsburgh, May 21-24, 1979.

6. Vora, M. K., Patel, J. G., Sandstrom, W. A., and Rehmat, A. G., "IGT U-GAS Pilot Plant Developments," Paper presented at the 14th Intersociety Energy Conversion Engineering Conference, Boston, August 5-10, 1979.

7. Gray, R. W., "MLGW-DOE, Industrial Fuel Gas Demonstration Plant," Paper presented at the Tenth Synthetic Pipeline Gas Symposium, Chicago, October 30-November 1, 1978.

COMPUTERIZED DATA ACQUISITION METHODS FOR IN SITU PETROLEUM RECOVERY EXPERIMENTS

Michael W. Thornton
U.S. Department of Energy, Laramie Energy Technology Center*

ABSTRACT

The Laramie Energy Technology Center has conducted several in situ field experiments for the recovery of fossil fuel substances. This paper describes the data acquisition and process control instrumentation that was used during recent in situ field experiments in tar sand combustion, oil shale retorting, and underground coal gasification. Specifics to be discussed include instrumentation for automatic gas sampling and analysis, underground temperature and pressure instrumentation, pressure and flow measurement and control, hardware configurations, and the software systems used to monitor, control, and record the processes.

The paper also includes comparisons of the instrumentation, computer hardware, and the software used on each of the three most recent experiments. The best features of these systems can now be adapted to future applications in the field or in the laboratory.

INTRODUCTION

The three experiments discussed in this paper were fielded from the summer of 1977 through the present. These projects are: (1) a tar sands combustion experiment, referred to as TS-2C, conducted approximately 6 miles west of Vernal, Utah, (2) an oil shale retorting experiment, RS-12, about 7 miles west of Rock Springs, Wyoming, and (3) an on going underground coal gasification (UCG) experiment near Hanna, Wyoming known as Hanna IVB. The tar sands data acquisition system was developed independent of any other field project. Next, the RS-12 system was developed using the

* Now with Westinghouse Hanford Company, Box 1970, Richland, WA. 99352.

hardware from the TS-2C project but drawing from techniques used on earlier UCG programs. Actually, the development of the RS-12 system and the modification of UCG software for the Hanna IVB project was done concurrently. So, the RS-12 system was an attempt to use the techniques of a larger computer system on a less powerful one.

IN SITU PROCESSES

Tar sands combustion, oil shale retorting, and coal gasification, each as in situ processes, require heat to reduce the petroleum product as it lies in the original formation to move it to the surface. Part of the fuel is spent in place to support the combustion necessary to each process. To sustain combustion, air must be forced into the reaction zone often under high pressure and at a high flow rate. All three processes also require water to be injected at times (either as water or steam). For coal gasification, water is a necessary constituent of the gasification reaction whereas the tar sand combustion and oil shale retorting experiments use it largely for cooling and oxygen dilution.

Generally, the resource is ignited in the formation at the bottom of an injection or production well. A combustion front then moves horizontally toward the sources of oxygen in other wells. Intermediate wells are stratigically located to intercept and monitor the combustion.

The products of all three processes are liquid and gas phases. For coal gasification, the product is a low Btu gas with some liquids in the form of coal tars and water with dissolved solids. In oil shale and tar sand extraction the gasses are more useful in determining the progress of the experiment. Liquid products (oils and water) are generally analysed away from the experiment site.

As we can see, all of these in situ processes require a common set of measurements to evaluate the experiments progress and provide decisive data.

MEASURANDS

Temperatures, pressures, flow rates, and gas analyses are the four major measurands recorded in these experiments. The temperatures of the process zone provide clear evidence of combustion patterns and motion. Meanwhile, temperatures in the surface equipment are useful to evaluate the experiment's operation, monitor injection and production system efficiencies, and watch for critical situations (eg. the temperature of tar sand bitumen in production lines must be kept above about 130°F to keep it mobile). Pressure measurements are made which reflect the zone's pressure pattern. Data is derived from observation, air injection, and fluid production wells. Surface pressures need to be monitored especially in the injection air manifolds, steam generation systems, and production equipment. Pressures are necessary to calculate the air injection and gas production flow rates. Although the flow rates are most often calculated (orifice metering), some flows, such as fuel and liquid flows, can be measured more directly. Gas analyses of the product and intermediate gasses often provide the most meaningful information on the combustion process.

Other measurands useful to these projects include liquid level monitoring in wells and in tanks, continuous gas species analyses (such as O_2 and CO), water saturation of gasses, oil/water mixtures, viscosity, liquid and solid analyses, measurements of water injected and total fluids produced, and atmospheric and environmental monitoring. Energy balance calculations also make it desirable to measure total electrical and petroleum energy spent in the experiment. Although not all of these measurands were available, most of them were accessable at any time with the real-time computing systems used to aid these projects.

UNDERGROUND THERMOCOUPLES AND OBSERVATION WELL COMPLETION

The underground temperature instrumentation for all of these projects specified the use of K - type thermocouples set in the reaction zone. Since Sandia Laboratories was responsible for the thermometry of the RS-12 and UCG experiments, I would like to describe the thermocouple arrangements used for the Vernal TS-2C project. Although we did not use any branched thermocouples or other in place diagnostic instrumentation, we feel that the results from the thermocouples and their multiplexing were quite good.

In each of the thirteen observation wells of the TS-2C well pattern, twelve stainless steel sheathed thermocouples (TCs) were bundled with the measuring junctions spaced at one foot intervals with the top junction positioned at the upper boundary of the tar sand zone. These TCs were then spliced to a twelve pair extension cable (type KX) fifteen feet above the top junction. This splice consisted of spaced, individually silver soldered splices which were heavily insulated and finally sheathed with a four foot length of 3/4 inch conduit to offer resistance to abrasion and bending. This whole assembly was finally filled with a liquid insulating material and capped with wax filled heat-shrinkable tubing. The extension cable was then continuous to a junction box mounted on the observation wellhead. Please refer to figure 1.

From each observation wellhead, see figure 2, the cables were routed via buried steel conduits to one of two large junction boxes holding 13 multiplexing relays. These were 36PDT relays with gold plated contacts designed for low level signal switching and were activated via control relays from the computer. Finally, the output cables of the two relay junction boxes were brought to another junction box, also in the well pattern, from which a single twelve pair cable was run to the computer's A/D backplane.

The three junction locations were quite helpful during the cable installation but did not interfere with the TC readings during the experiment. Although some initial criticisms were made of the relaying of TC signals, it proved to be extremely reliable and absolutely trouble free. The relaying network was also much more economical than using nine additional multiplexing cards in the computer plus the extra cable and connectors that would have been needed. Since the temperature sampling rate was quite low, every six minutes for all TCs, plenty of time was available to do switching and wait for the signals to settle. To help clean up the noise on these inputs and make open TCs apparent, a fourteenth relay was used to switch all inputs to ground (discharging the A/D input capacitors) between each well. Thus, an open TC would be read as a zero potential rather than floating at the level of the corresponding TC in the previous well.

Although the underground gas sampling assemblies also installed in these observation wells were not entirely successful, I would like to describe them as I discuss the completion of the wells. The method of well completion was important in the success of the thermometry.

Referring again to figure 1, a gas sampling tube, 1/8 inch pipe, was placed in the open well bore parallel to the TC extension from the wellhead to the upper boundary of the test zone. At the lower end a junction was made to a ten foot length of one inch pipe which extended through the tar sands. This pipe was slotted and then wrapped with 1/16 inch mesh screen to block solids from the sampling tube. This mass of steel was insulated from the TC bundle with asbestos blocks before inserting the assembly into the well bore to prevent the slurring of temperature readings by heat conducted along the pipe. The top end of the gas sample tube was connected to a current loop type gauge pressure transmitter and a valve arrangement to permit sampling of the reaction zone gasses. (See figure 2.) Once the assembly was in place, no. 10 sand was used to fill the open hole to the top of the tar sand layer. This sand was too large to invade the gas sampling tube, but allowed a good interface to the tar sand. (As the combustion front would pass by, the bitumen would mobilize into the sand and thus make it appear as part of the formation.) The no. 10 sand was followed by a five foot layer of fine sand as lost circulation material acting a barrier to the cement that was poured on top. (We did not want to create a solid core around the TC package.) Finally, cement was used to plug the well bore. Although we used about fifteen feet of cement, I would recommend a good deal more to prevent the leaching we experienced. Fifteen feet of cement is sufficient to hold back the pressure (up to 500 psig in this test) but some of the bitumen forced a path around the plug and presented itself as an unexpected mess at the surface. Even with this intrusion the TCs provided good data.

AUTOMATIC GAS SAMPLING

The gas analyses for these experiments has typically been done with microprocessor controlled gas chromatographs (GCs) with temperature programming abilities. Early experiments required an operator to manually inject a gas sample, start the analysis, and then type the data into the computer. Improvements were made in the sampling system as well as interfacing the GCs to the host computers. Now, as with the RS-12 and Hanna experiments, the computer automatically selects the sample points, initiates the analysis, and interrogates the GCs for the data. Complete analyses are thus available as hard copy from the GC, optional hard copy on the system's line printer, and in mass storage for future recall and for real-time calculations.

Let's examine the RS-12 sampling system. Two Hewlett-Packard 5830 gas chromatographs were used full time with a third in standby. One of these was used to continually monitor the production line gasses. Since up to three production wells could be monitored at any time, the operator was given the option to designate which gas streams, in any combination, were to be tested. From this point, the computer would take samples every hour until the operator requested a stop. The second GC was used similarly but could access up to 48 gas sampling ports through a series of computer activated solenoid valves. For this GC, a file was used to hold five days of sampling sequence information. An operator, through a special program, would then describe the sampling sequence to the computer in his own language. Before the sequence file would run out the operator was alerted to update his file. He could then enter any new sequence or reinstate the old one. The flexibility of this sequence definition file also provided for calibration analyses and for periodic halts for maintenance.

Both chromatographs were automatically set (by software) to run only once per hour but this limitation was due only to the type of data base used to store the data. (The data base will be discussed later.) Since the experiment was dynamic and the computational load would change, the initiation or final interrogation of a GC might easily be delayed. Delays were accepted by the operating system and compensated in the following runs. Since the GC cycling time was actually set for 55 minutes, but not twice in the same hour, the scheduling would eventually make up the time lost in the delay. For example; if a GC was 15 minutes late in starting this hour, then next hour it will start 10 minutes late, 5 minutes late the next hour, and it will start at the normal time three hours from now.

PRESSURES AND FLOWS

Two of the experiments were instrumented for pressures primarily using current loop type transmitters. Gauge pressures were measured at the observation wellheads, air injection and gas production wellheads, and at various stages of the surface equipment. No significant difficulties were encountered in monitoring pressures except in observation wells where the tubing frequently plugged with tar or frozen condensate.

Orifice metering was used to measure all injection air and steam and production gas flow rates. (See figures 3 and 4.) Again, current loop type pressure transmitters were used to read the absolute static and differential pressures. The pressures on the air injection lines were read more reliably with the aid of pressure snubbers to help eliminate the rapid pulsing often created by the compressors. At some locations (and in earlier experiments) voltage output (strain gauge) type transducers were used but with less satisfactory results. Although this may have been due to less stringent procurement specifications, the current loop transmitters were still easier to maintain and use with long cables to the computer's A/D.

Control of injection air was attempted on the TS-2C experiment using electro-pneumatic valves under direct computer control. Although the control was partially successful, the motor valves were a poor choice. Much better control has been achieved in the use of analog controls supervised by the computer (1). With the valve position continuously corrected by the closed loop analog device, the computer was used only to provide the set points of the desired flow rates. This type of control has been successfully in use on the Hanna projects for two years.

THE COMPUTER HARDWARE

The instrumentation for each of these field experiments was designed around a mini-computer based data acquisition system (DAS).

The Vernal TS-2C experiment used a Hewlett-Packard (HP) 2100A CPU with 32K words of core memory and a HP7900A disc drive with 4.9 Mbytes capacity to hold the operating system and data base. (See figure 5.) A HP7970 magnetic tape drive was used for periodic system backup and temporary data storage. All analog data were digitized by a HP2313 A/D subsystem. Transient suppression devices were connected to all inputs at the A/D backplane. An ASCII Party Line, 53A from Computer Data Systems, was used to interface a real-time chronometer (with battery backup) to the CPU. Gas analyses were performed with a HP5830 gas chromatograph. Although it was our intention to interface this GC to the computer for this project, the software was never finished and the data was entered into the computer by the operators. Hourly and daily reports of the experiments progress were presented on a HP2767 line printer. Other information was available upon demand at the line printer, either of two CRT consoles (a HP2600A and a HP2640B), or on the HP7210A X-Y plotter. A Texas Instruments Silent 700 terminal was used to permanently record all system flags and errors. Communications to Laramie was made via a Bell 103 modem in Vernal to another TI Silent 700 in Laramie. Control was provided through reed relay interfaces to a bank of 64 115VAC relays which in turn powered the thermocouple multipexers, motor valves, and alarms.

The Rock Springs site 12 experiment had two data acquisition systems on the site. The HP based system from the TS-2C experiment was upgraded for use in Rock Springs and was interfaced to a Modcomp based DAS designed and operated by Sandia Laboratories. Improvements to the HP system included a HP2648A graphics CRT console with a HP7245A printer/plotter for hard copies of any CRT display. A HP2607 line printer (wide format) was added and the HP2600A CRT was deleted. Two HP5830 GCs were used and both were interfaced to the computer for automatic gas sampling.

Sandia's Modcomp system was interfaced to the LETC HP system as though it another terminal. Thus, the HP computer was able to use an existing I/O driver (DVA05) and a 9600 baud asynchronous interface board (HP12966). Optical isolation line drivers were used to electrically separate the computers and drive the interfaces over the gap (about 150 feet).

The two gas chromatographs were linked to the HP CPU using techniques proven on earlier Hanna experiments. Again, existing software (DVR00) and hardware (HP12531D) were used. A Vadic modem was installed to provide a 1200 baud communications link to Laramie but hardware difficulties and problems with telephone lines kept us from establishing a working link before the end of the experiment.

The Hanna IVB project used the same hardware configuration as the earlier Hanna III and IV experiments. (See figure 6.) The CPU was a HP21MX-E mini-computer with 128K words of solid state memory. Three HP7905A disc drives provided 15 megabytes of space each (one drive was for backup) and a HP7970 magnetic tape drive was used for periodic storage of the system. The superior memory of this system was a huge advantage in running fast data acquisition and supporting graphics routines concurrently. Since a data base of 300 days (versus 75 days for RS-12) could be managed on a single disc drive, the disc files were never changed within the duration of an experiment.

The analog inputs for Hanna were divided between the HP2313 A/D subsystem and a Fluke 2240A data logger. The HP2313 was capable of faster and random channel accesses and the Fluke was used for a large number of inputs to it's multipexers on the well pattern. The Fluke transmitted data to the CPU over an RS232C interface to the computer some 500 feet away. Due to the type of interface used by the HP2313, the A/D was restricted to be within 15 feet of the CPU.

Gas analyses at Hanna were obtained by two HP5840A gas chromatographs, one for the production gases and one for the monitor well gases. This time, the computer was used to sense when a sample was manually injected into the GC and schedule an interrogation program to run 25 minutes later. There were no sample tubes for automatic sampling from monitor wells. Production gases, however, could be sampled automatically after the 'linking' stage of the experiment and gasification was started. Normally, an identification number was entered with the time for the sample whenever an operator injected a sample into a GC. This ID was used by the computer to identify the analyses stored in the data base. The interface used was the same as discussed for the RS-12 GCs.

THE COMPUTER SOFTWARE

All three projects utilized Hewlett-Packard supplied operating systems. However, the data acquisition programs for each system were rewritten and largely unique for each project. Table 1 shows a comparison of the operating environments for the three systems.

	TS-2C	RS-12	Hanna IVB
Operating System	RTE-II	RTE-II	RTE-III
Partitions	2	1	10
Common Area	256	400	2500
Measurands	186	500	600
Data Base Length	35-40 Days	75 Days	300 Days
Summary Access	Very Good	Slow	Very Good
Serial Access	Poor	Very Good	Very Good

Table 1. Operating environments for the three in situ experiment data acquisition systems.

The Rock Springs 12 software built upon many of the advantages of the Hanna software while working under the limitations of the Vernal hardware. The results were very improved over the Vernal system and had some qualities above the Hanna system. (The Hanna IVB software was largely a modification of the existing software developed for the Hanna III and IV experiments.) On a single disc drive, the RS-12 system contained a modular set of programs commanded by a single controlling program, a table driven set of data acquisition routines, a very flexible set of operator's programs, and a compact but accessable data base.

The control program was used to schedule all data acqusition, data storage, and data reporting programs. Although the operator had complete control over all functions of the system, he did not directly access them. He could start, stop, and change the rate of any of the seven major functions but the control program handled the timing and scheduling. These functions were: data acquisition, transfer of data to the Modcomp computer, transfer data from the Modcomp, auto-analyses from GCs 1 and 2, periodic printed summaries, and hourly storage of data. As mentioned before, the operator determined the gas sampling sequence for automatic analyses. He could also change the entire injection and production flow pattern in the computer's logic to reflect any plumbing changes that might be necessary.

The data base for RS-12 was very similar to the Hanna data bases but consisted of only seven files (instead of about 60), one for each major data specie. All data species were stored chronologically and contiguously for rapid access in plotting and time varient analyses. Another small file was used as a directory to locate any data type, it's format, and a descriptor useful for plot lables and reports. With the exception of underground temperatures, every measurand was uniquely identified in this file and in every record of the data base by a two letter code. The codes were mostly used for 'look up' by the plotting routines.

CONCLUSIONS

In the past four years at the Laramie Energy Technology Center, the development of better data acquisition systems has taken a more prominent role in all field experiments. The hardware developments have come from both industry and from within the center. Software techniques have improved ten fold and will continue to do so. We are taking more data in less time, over longer periods, and producing better analyses. Present efforts include the development of an asynchronous interface to the GCs, more generalized DAS software, improved graphics, and a cetralized DAS with satellite field systems.

REFERENCES

1. Moore, King, Lanum, and Smith, "Data Acquisition and Process Control Instrumentation for In Situ Coal Gasification" from the 7th Annual Mining and Metallurgy Division Symposium and Exhibit, Nov., 1978, Denver, Colorado.

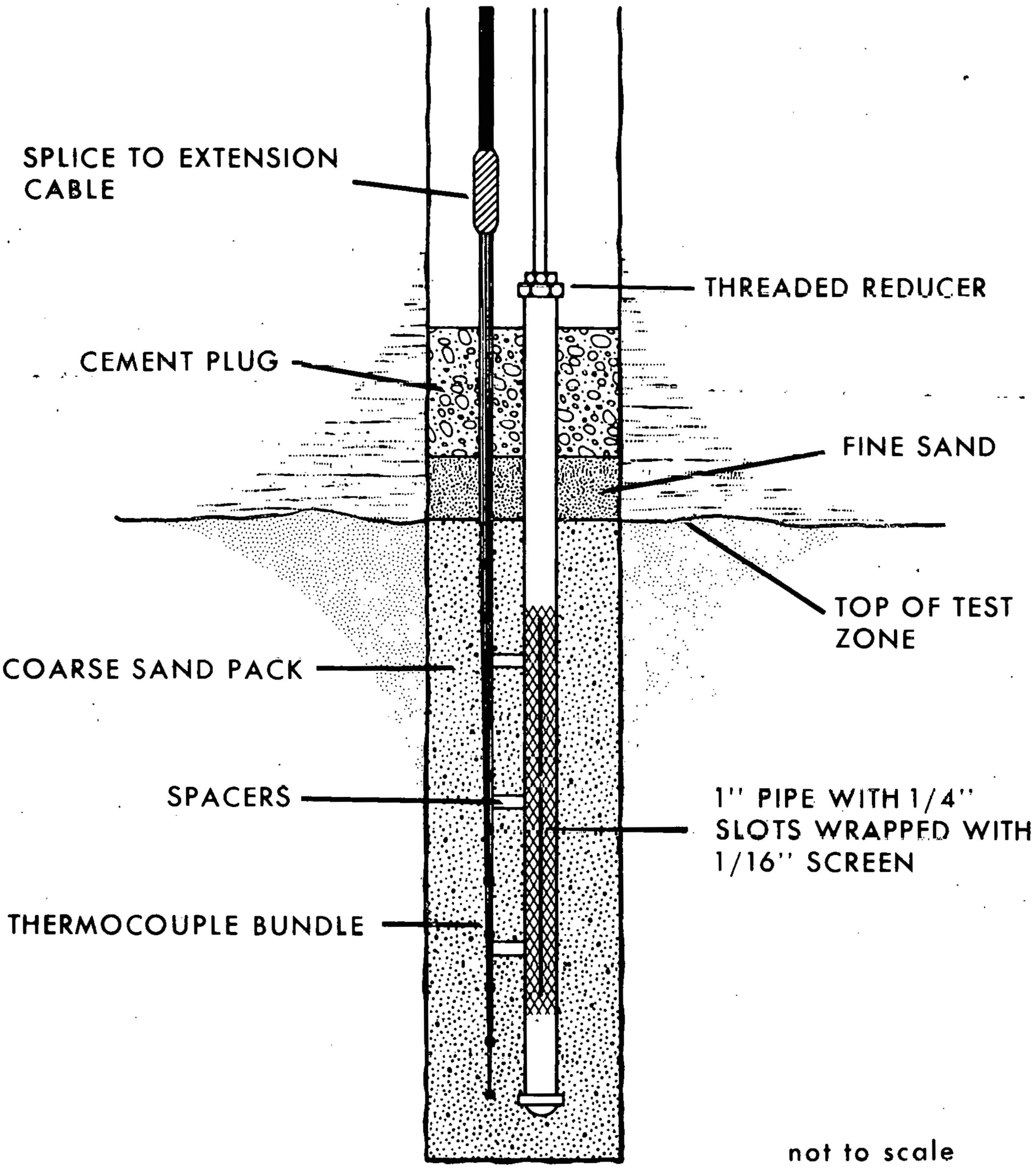


Figure 1. Observation well completion.

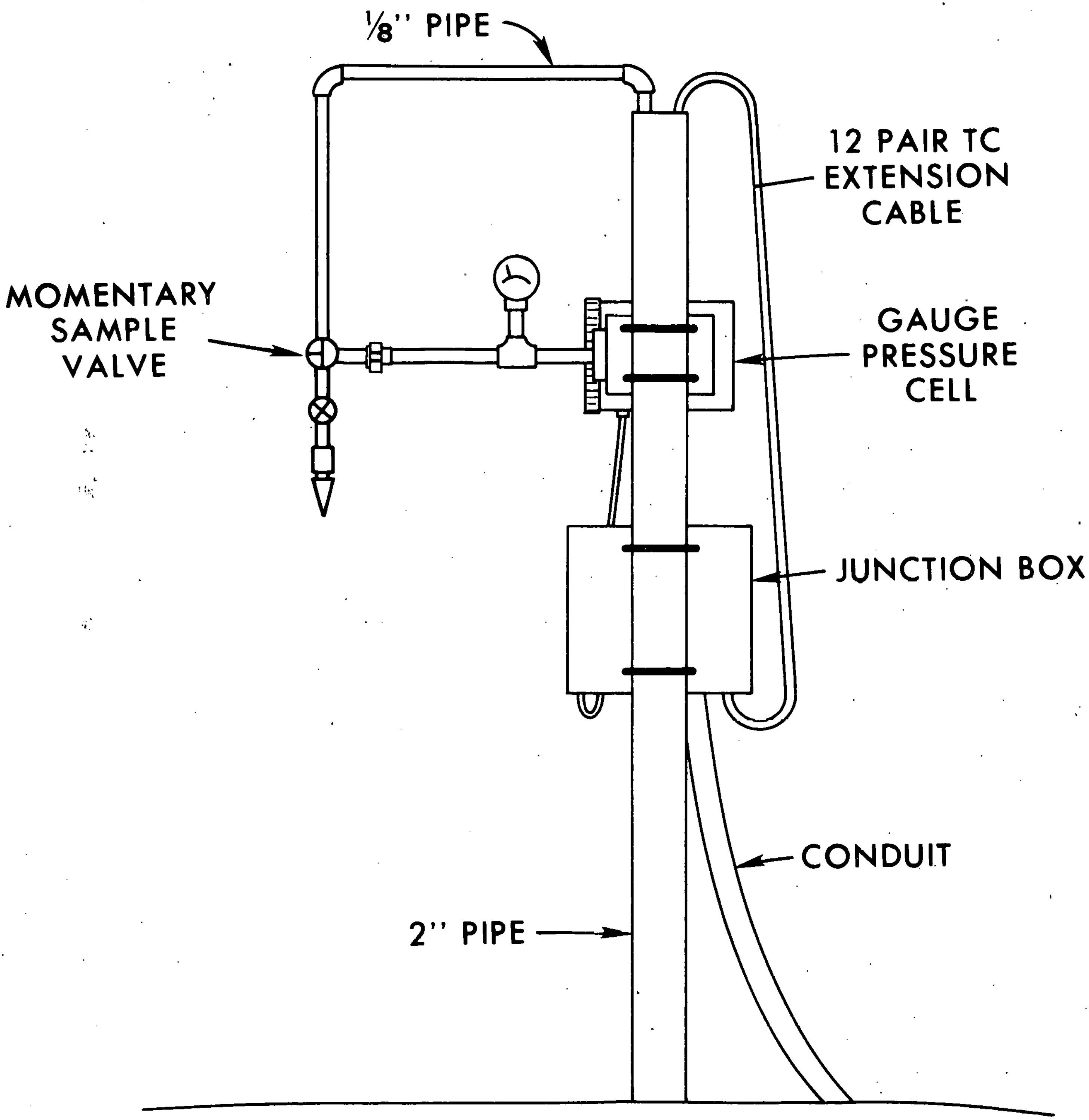


Figure 2. Observation wellhead assembly.

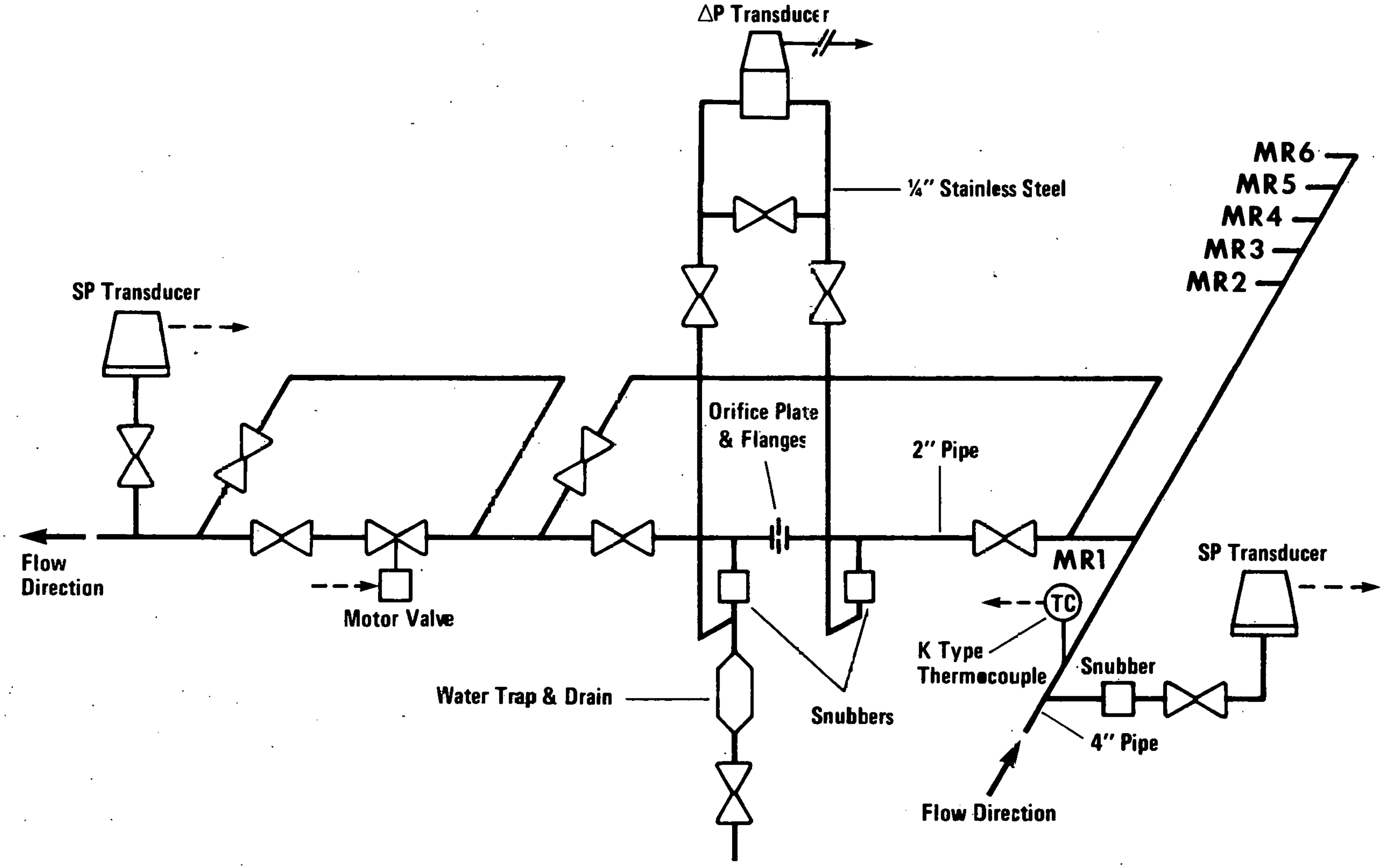


Figure 3. Air injection metering for TS-2C.

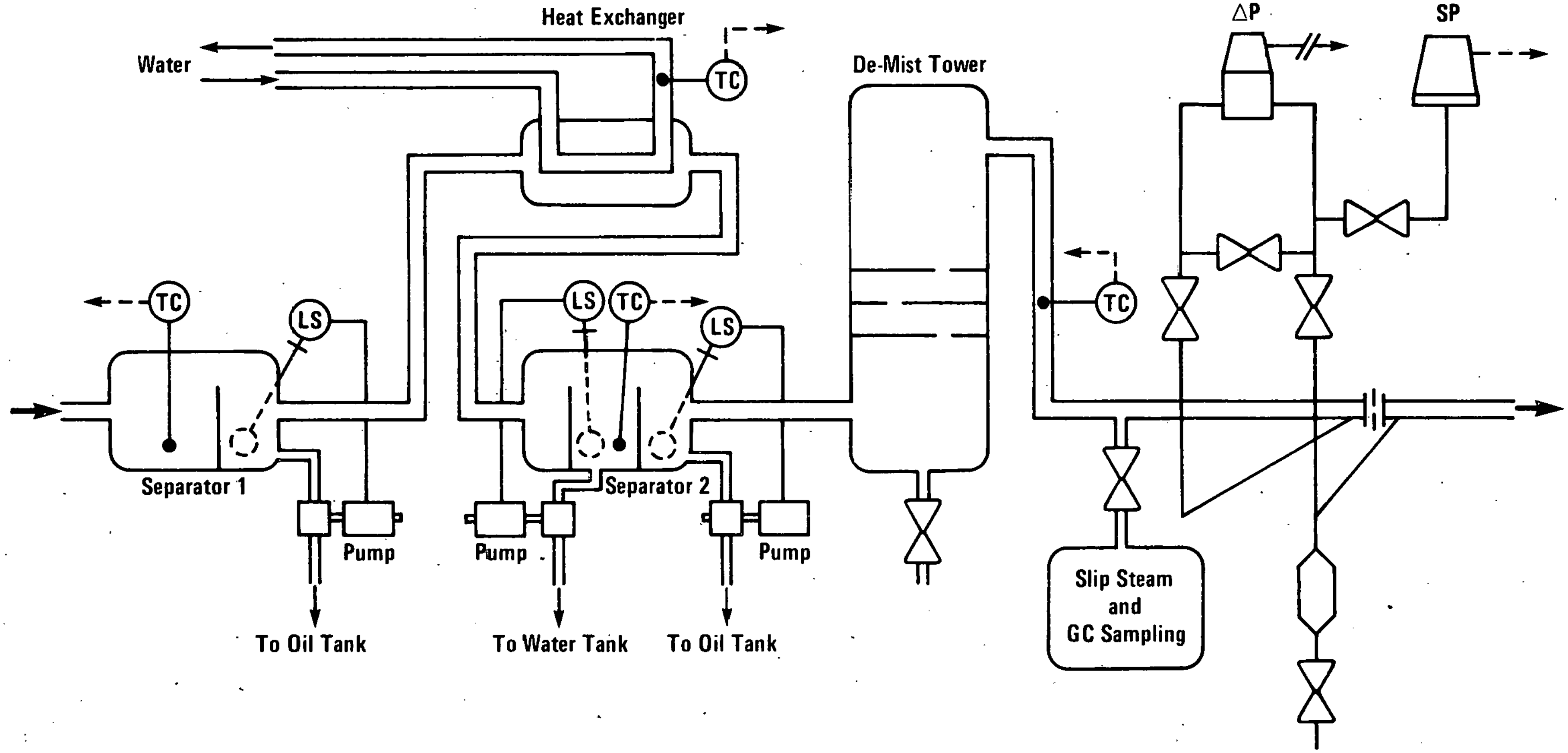


Figure 4. Production stream metering for TS-2C.

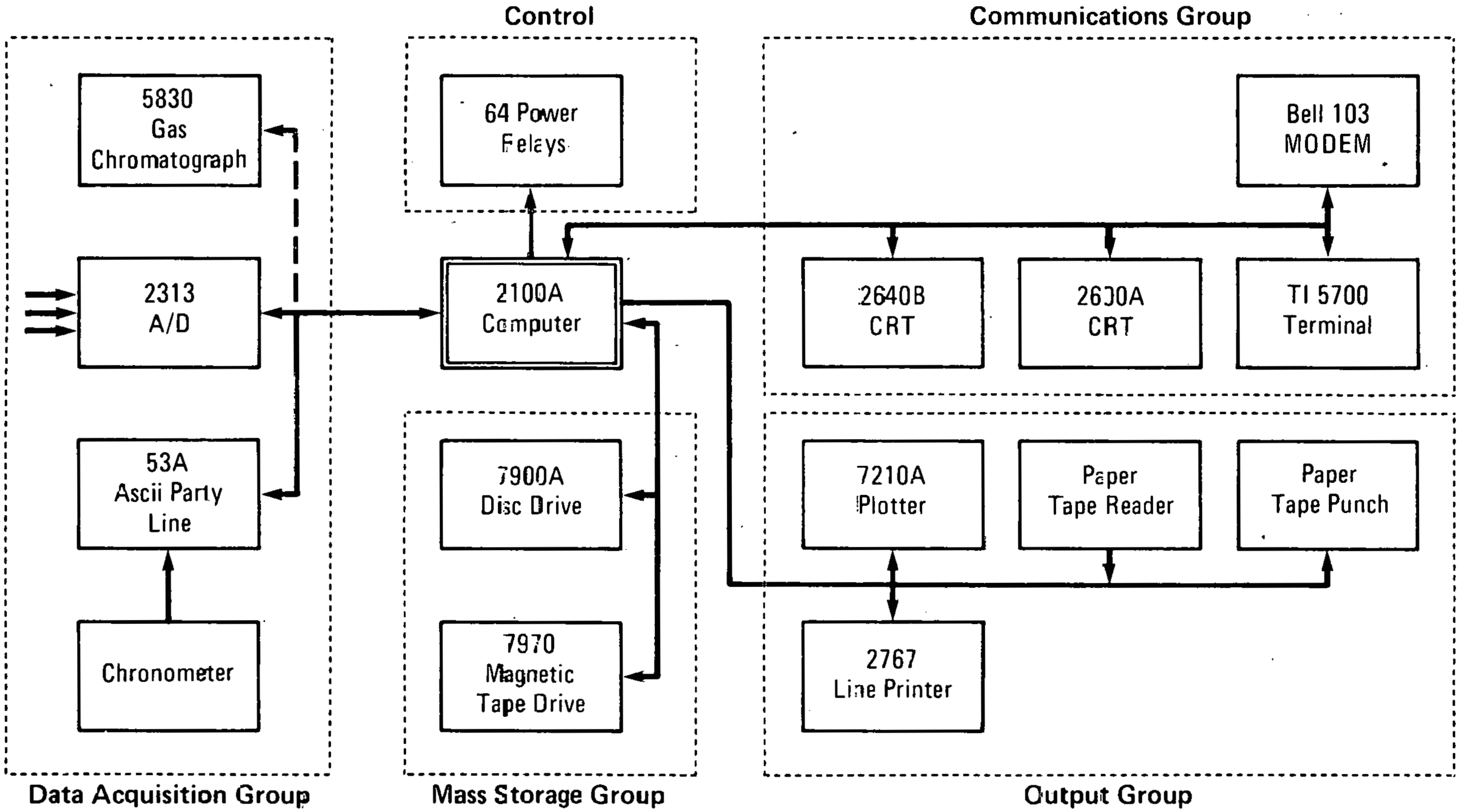


Figure 5. Hardware configuration for TS-2C.

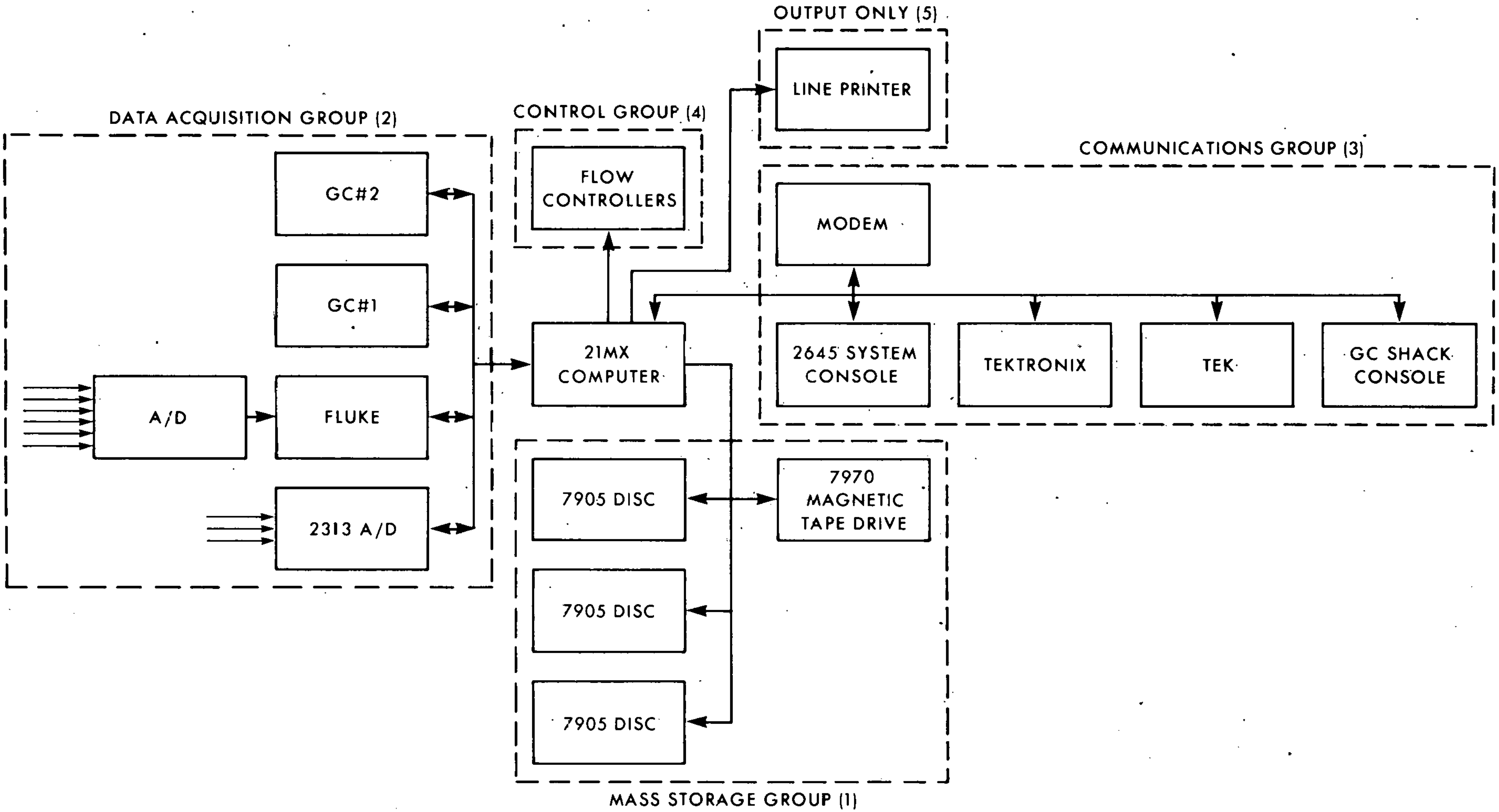


Figure 6. Hardware configuration for Hanna IVB.

INSTRUMENTATION NEEDS FOR A HIGH BTU COAL GASIFICATION DEMONSTRATION PLANT

Herb C. March
Procon Incorporated

ABSTRACT

This paper discusses the instrument and control system requirements for the proper operation of a high Btu Coal Gasification Demonstration plant utilizing the HYGAS process. The needs and problems encountered in the measurement of slurry flow, fluidized bed levels, reactor surface temperature, and process component analysis is presented. Some proposed solutions and considerations for adequately obtaining these measurements are also discussed.

NOTICE

INSTRUMENTATION NEEDS FOR A HIGH BTU COAL GASIFICATION DEMONSTRATION PLANT

Herb C. March
Procon Incorporated

1. INTRODUCTION

The HYGAS process, like any other coal conversion process, requires adequate measurement of certain variables for proper control and operation. Due to the hostile environment in the process, presently available instruments are either incapable of withstanding this environment for any length of time or don't exist since the measurement wasn't needed before. This leaves the designer with two methods to use in solving the problems of process measurement. The first, and probably the most significant, is to design the processing equipment so that these "problem measurements" will not be needed at all or their number reduced to a bare minimum. The second method is to modify and/or supplement presently available instruments to make those measurements necessary for process operation and analysis.

This paper discusses some of those areas where the need for the process measurement could not be "designed out" and is essential for acceptable plant operation.

2. COAL/OIL SLURRY FLOW

In order for the HYGAS gasifier to operate properly, its char/oil slurry flow rate has to be measured and controlled to maintain a steady feed rate to the gasifier. Refer to Figure 1. This key process variable is also used to set the controls for the coal pretreater, char/oil mix tank and the gasifier slurry feed pumps. This equipment must operate together to meet the char feed demand of the gasifier.

Slurry Flow

Due to the highly erosive nature of the slurry feed to the gasifier reactor, a simple direct in situ flow rate measurement cannot presently be made. However, this flow rate can be determined with reasonable accuracy by measuring the slurry feed pump's speed and slurry density, then calculating the mass flow rate using the following relationship:

$$Qs = Srvw$$

Where: Qs = Mass flow rate of slurry in lbs /min

S = Speed of turbine pump driver in RPM

r = Reduction gear ratio of drive

v = PD pump's volumetric displacement per revolution in ft^3

w = Specific weight of char/oil slurry in lb /ft^3

Both turbine speed and slurry density signals are sent to a multiplying device that performs the flow calculation. The slurry feed pump turbine's speed will be determined by a tachometer which sends a 4-20 mA D.C. signal to the multiplying device.

The main factor affecting the results of using speed measurement to determine the pumps volumetric displacement per unit time is that the pump volume must stay constant. Unfortunately, the erosive nature of the slurry can erode the slurry contact surfaces of the pump causing the pumps volumetric displacement to vary. The internal parts of the pump should be initially measured and recorded, then periodically inspected and remeasured to determine this rate of wear and the effect it makes on the displacement volume of the pump. This effect can then be compensated for by a factor added to the pump's volumetric displacement during system recalibration.

Slurry density

The density of the slurry can be measured in the slurry mix tank by measuring the differential pressure between fixed points with a known vertical separation in the slurry volume. Refer to Figure 2. This "pressure head", as measured by a differential pressure transmitter, is directly proportional to the slurry density provided the slurry is mixed to keep the solids suspended in the slurry. This relationship can be expressed by:

$$\rho\text{ (actual)} = \frac{Hr}{H_1}\rho\text{ ref.}$$

Where:

ρ (actual) = the slurry density

ρ ref. = the reference density

Hr = the distance between sensing points

H_1 = the measured differential pressure

Each pressure sensing line of the transmitter should utilize a remote diaphragm seal element to keep them free of solids and prevent plugging. These diaphragms are installed directly into the tank wall. Preferably the diaphragm sensing surface should protrude into the tank where it will be kept free of solids by the agitation of the slurry in the tank. The diaphragm seal's span should be selected so that it is as close as possible to the "pressure head" being measured to ensure high sensitivity and accuracy in the pressure measurement. The seals should also be removable so they can be cleaned periodically.

An alternative to diaphragm seals would be the use of a continuous oil purge through the transmitter sensing lines. The purge flow and pressure in the sensing lines must be kept constant relative to each other to prevent errors in the actual pressure differential to which the transmitter diaphragm is exposed. The supply pressure to the purge rotameter should be at least 20 psi above the operating pressure in the slurry mix tank to prevent the back flow of solids into the sensing lines when process pressure upsets occur.

Back-up Slurry Flow Measurement

A back-up, or alternative method of measuring the slurry flow would be the use of an elbow flow meter. Refer to Figure 3. The elbow meter is a head type meter like an orifice meter, however there is no obstruction in the line to erode, distort or plug up from the solids in the stream. (Reference 1). Other advantages are: 1) The improved sensitivity the device has to flow changes, i.e., the developed pressure differential is 2 to 4 times larger than a venturi or orifice plate with the same beta ratio. Since the slurry stream pressure is about 1350 psig, the higher developed pressure differential increases the signal gain of the D.P. transmitter which should result in better performance. 2) Remote diaphragm seals can be used on the pressure sensing lines of the transmitter to isolate it from the process.

The elbow meter generates a differential pressure between pipe wall taps caused by the flow stream's change in direction as it passes through the elbow section of the meter. This differential pressure is proportional to both flow rate and fluid density of the slurry, consequently the density has to be measured to obtain the same accuracy as in the positive displacement method. The differential pressure transmitter's sensing lines would utilize remote diaphragm seal elements to prevent them from plugging as mentioned before. The diaphragm surface should be mounted so that it is flush with the pipe wall and removable for inspection and service.

An alternative to the diaphragm seal would be an oil purge. The same consideration discussed for purging the density differential pressure transmitter also apply here for best results. The purge supply pressure should be at least 50 psig above the maximum operating pressure in this case.

To obtain an accuracy close to that of the pump volumetric displacement method, the meter will require shop calibration for a specific set of flow conditions with a constant slurry density, then will have to be field calibrated for different densities. The positive displacement method of flow measurement could be used as a reference for this field calibration.

As with the pumps, the elbow meter would have to be periodically pulled out of the line and inspected internally for wear, especially around the pressure sensing areas.

3. DILUTE PHASE SLURRY FLOW

The raw gas from the gasifier goes to a quench tower where it is cooled and scrubbed of coal fines with water. Refer to Figure 4. The quench water is recycled back to the quench section of the tower via a pump. This recycle quench water flow needs to be measured to determine the operating status of the quench tower. Since the solids concentration is approximately 8% by volume in quench water, this flow can be measured by a thermal flowmeter. Refer to Figure 5. The flowmeter consists of an in-line flow tube with temperature sensing elements on the outside surface of the tube. These elements are energized with a small amount of electrical energy, generating heat which is conducted away from the element by the flow stream. This phenomenon is measured and calibrated to be proportional to mass flow of the fluid. Additional sensing elements are located on the tube to compensate and correct for the effects of fluid and ambient temperature.

The major advantage of using this type of flowmeter is that it doesn't require the remote diaphragm seal elements or the complex purging system required for the head types. A disadvantage is the initial need for extensive field calibration at operating conditions to ensure reasonable accuracy in the flow measurement.

4. FLUIDIZED BED LEVEL

The measurement of fluidized bed heights in the gasifier is essential for maintaining the pressure balance between gasifier stages thereby controlling the gas production rate. Presently, the only practical method for determining these bed heights is by differential pressure measurement between fixed points with a known vertical separation and located within and above the bed. Refer to Figure 6. In this case, the remote diaphragm seals cannot be used to prevent the sensing lines from plugging because they cannot withstand the high pressure (1250 psig), high temperature (1950°F), corrosive elements and erosion from solids for any length of time. The only technique that can be used with any success is a continuous inert gas purge through the lines into the gasifier. To minimize the problems encountered in using this method, the following practices should be implemented to minimize plugging of the lines and measurement errors:

1. The purge gas should be inert, moisture free and heated. The purge gas flow rate has to be closely controlled and high enough to maintain a gas velocity above 0.2 ft per second at operating conditions in the sensing lines.

2. The purge gas supply pressure should be at least 100 psig above maximum operating pressure to prevent solids backflow into the lines when pressure upsets occur.

3. The sensing lines should be as short as possible with the minimum number of elbows to ensure the gas velocity is maintained above 0.2 ft per second.

4. The purge gas supply should be located as close to the sensing diaphragm as possible to maintain a sweeping type of purge along the complete length of the lines.

5. The differential pressure transmitter must be located above the elevation of the highest tap to insure all condensibles drain back into the vessel.

6. A steam tap should be installed in each line near the vessel tap to blow out solids that may accumulate in these areas during operation.

The level measurement has to be corrected for changes in bed density to determine the true fluidized bed height in the vessel. The density should also be measured by a differential pressure transmitter installed in the same manner as the level transmitter except both pressure taps are located at least three feet below the lowest operating level of the bed to minimize channeling of the gas through the bed.

5. REACTOR EXTERNAL TEMPERATURE

Two refractory lined sections of the gasifier operate at internal temperatures of 1700^o to 1950^{o}F. If the refractory lining cracks or otherwise fails, the reactor steel will be unprotected and overheat, causing an unsafe condition. This refractory failure must be detected quickly, the reaction stopped, and the reactor's internal pressure reduced as low as possible. In order to detect these "hot spots" on the outside surface of the vessel within a reasonably short period of time with good accuracy, long length continuous thermistor sensors should be used.

The particular type of thermistor to be utilized possesses a negative temperature coefficient. Its resistance decreases as the temperature it is sensing increases. Refer to Figure 7. It can be manufactured in 100 foot lengths and cover an area approximately 8200 sq. ft. A vertically oriented serpentine pattern with a spacing between elements 10-12 inches will require approximately 100 thermistor elements to monitor the two reactor sections. Refer to Figure 8.

This thermistor system is recommended for detecting temperatures on pipe and vessel walls and has been used at the Synthane Pilot Plant, Bruceton, Pa., for monitoring the reactor vessel's wall temperature. (Reference 2).

The following principles affect the operation and accuracy of this system:

1. Proper attention should be given to the method of mounting to ensure tight contact of the thermistor with the surface of the wall for all operating temperature variations. The manufacturer recommends stud fasteners welded to the vessel. Refer to Figure 9.

2. The resistance of the element gives a signal that is proportional to the mean effective temperature of its total length. Thus, a small, very hot spot on the element's length would be averaged out and give the same signal as a large area that was at a lower temperature. The sensitivity of the element can be improved by reducing the area monitored, thereby reducing the element's length and total resistance.

The following factors should also be taken into consideration prior to installation:

1. Large temeperature differences across the vessel area being monitored by each element.
2. Resistance vs. temperature characteristics of each element.
3. Area size monitored by each element and the proximity of elements to each other.
4. Selection of the element holding apparatus.
5. Required accuracy of the system as installed.

The manufacturer claims an achievable accuracy of approximately ±5% of temperature or ±25°F , whichever is greater. The smaller the area monitored by each element, the better the sensitivity and accuracy.

This system can be utilized in conjunction with a portable I.R. temperature sensing device so that when a particular element on the reactor indicates a high temperature, the actual problem area can be pin-pointed with the I.R. device.

6. PROCESS COMPOSITION ANALYSIS

Composition analysis of the required process liquid and gas streams can be adequately done with an on-line gas chromatograph. Gas chromatography has been utilized extensively in chemical and hydrocarbon processing for many years. As a result of this, the analyzer portion of a process gas chromatograph system is well developed and trouble free if maintained properly. However, due to the nature of the coal gasification environment (i.e., high temperature/pressures and particle contaminants), the sample conditioning system will require adequate design to handle these conditions.

Sampling System

The sole purpose of a sample system is to transport a representative sample from the process stream to the analyzer without affecting the components to be analyzed. It is important that the following factors are considered in the design of the sample conditioning system:

1. Sample taps should be located so that a representative sample is taken. Process circulation loops should be designed so as to ensure that a fresh sample is available to the analyzer at all times. This is especially important when the composition analysis is to be utilized for closed loop control. A method of minimizing the system response time would be to utilize smaller diameter elution columns within the analyzer. Location of the analyzer close to the sample tap to reduce the length of sample line would also improve response time.

2. The sample filtration system should be carefully designed to incorporate proper macro as well as micro filtration without significantly altering or reducing the velocity of the sample.

3. All sample, vent and return lines, valves and other hardware, should be properly heat traced and insulated as required. This, combined with proper pressure regulation, will ensure that the sample will be transported properly in reference to its physical state (i.e., gas, liquid).

4. Safeguards to prevent cross stream sample contamination should be incorporated by purging the sample lines with clean, inert gas between each sample. The analyzer should utilize a quality sample and column switching valve with positive selection and shutoff characteristics. The control system for the gas chromatograph should also be equipped with power interrupt lockout modules. During power dips, this would prevent the timing system from allowing another sample to be injected into a column before the previous one has eluted through it.

Once the chromatograph system is in operation, the accuracy of its analysis should be checked against a grab sample analysis by an off-line chromatograph. Material balance calculations can also be used as a check of the analysis.

Component Analysis of Solids

At the present time, most of the component analysis of coal, char and ash can only be done off-line in the analysis laboratory. These techniques are time consuming and in certain cases the analysis cannot be used for process control since it is obtained much too late. There is a great need to develop techniques and instruments capable of doing this analysis on-line and much faster in order to make timely process adjustments. It is felt that once this capability has been commercialized it will give the process designer a very powerful tool for optimum plant design and directly impact on plant costs. (Reference 3).

Some of these more important analysis measurements are:

1. Moisture measurement in coal is needed to determine its rank and calorific value. The independent measure of moisture and total hydrogen content are combined to determine the relative amount of hydrocarbons in coal.

2. Hydrogen measurement in coal is needed to establish the relative content of hydrogen in water and volatile matter to determine the coal's rank and calorific value. In addition, the measure of total hydrogen can also determine moisture variations during the drying process.

3. Sulfur measurement in coal is needed to detect when the sulfur content deviates outside the limits of plant design. The "off-spec." coal could be diverted to storage and/or blended with other "on-spec." coal.

4. The various elements in the ash, such as carbon, silicon, aluminum, iron, nitrogen, sodium, calcium, potassium, titanium and chlorine, need to be measured to permit "off-spec." coal to be diverted to storage so a constant ash level and composition in the gasifier can be maintained.

5. The pretreater reactor is required to destroy the agglomerating characteristics of the coal supply to the HYGAS gasifier. The pretreater's operation is checked by determining the free swelling index of the char in the laboratory. The on-line determination of the char's free swelling index is needed to ensure continuous pretreater operation and to avoid agglomeration of the char in the gasifier.

6. A rapid analysis of either the carbon or ash content of the spent char is needed to access the carbon conversion of the feedstock to the gasifier. Spent char can then be removed from the bed based upon this analysis to provide a more uniform operation of the steam-oxygen bed and assure a more clinker-free operation.

7. CLOSURE

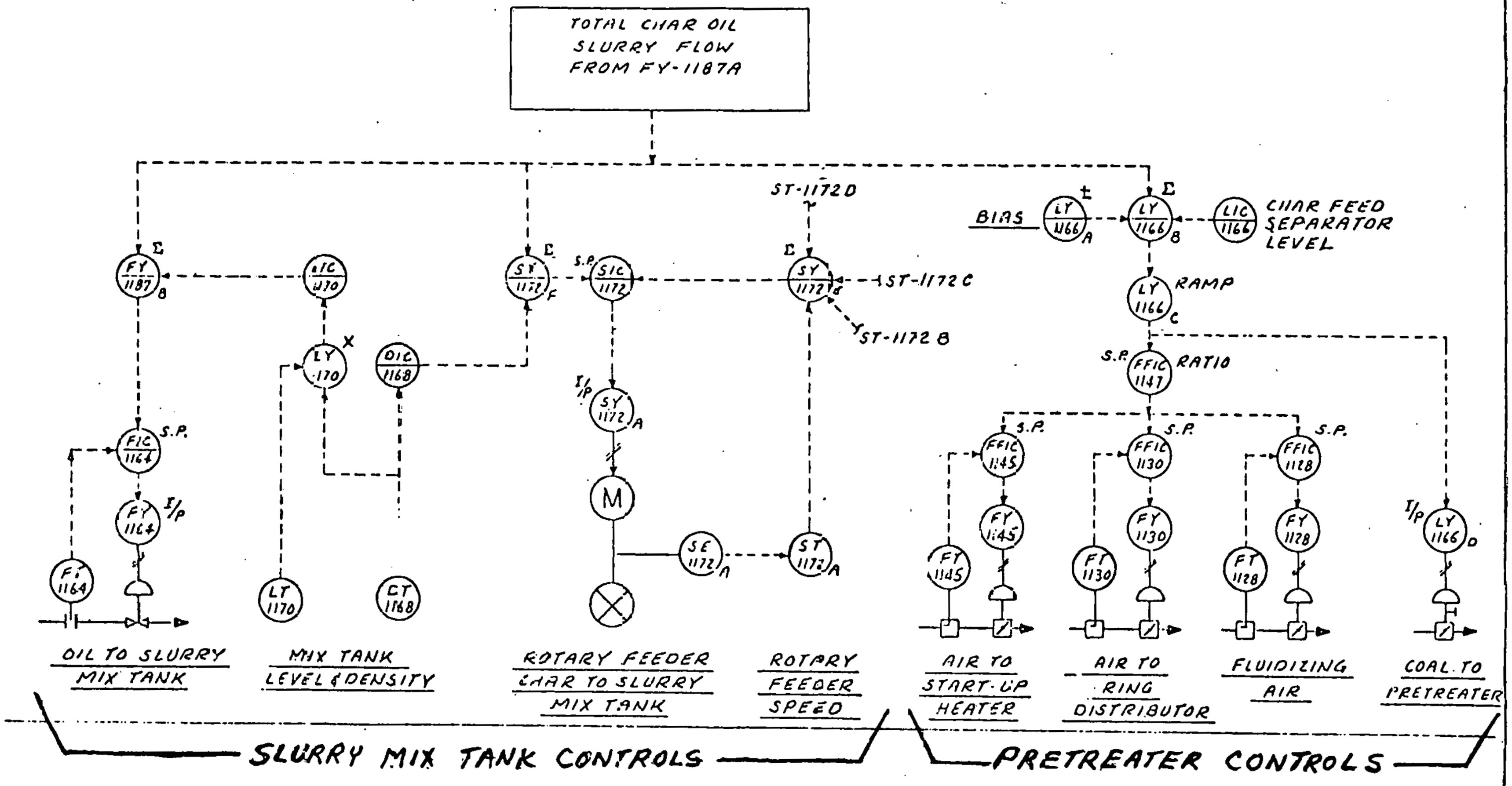
This discussion of various process measurement needs is meant to point out those areas where problems still exist to varying degrees. Considerable development is presently being done under the sponsorship of the Department of Energy to solve these problems and satisfy these needs, especially in slurry flow measurement and solids component analysis. It is recommended that the designer survey these areas to insure he can take advantage of any new, recently commercialized instruments before he commits to a particular control scheme.

REFERENCES

1.) "Take a Second Look at Elbow Meters for Flow Monitoring", by Dr. E. G. Houptmann, October, 1978 issue of Instruments and Control Systems.

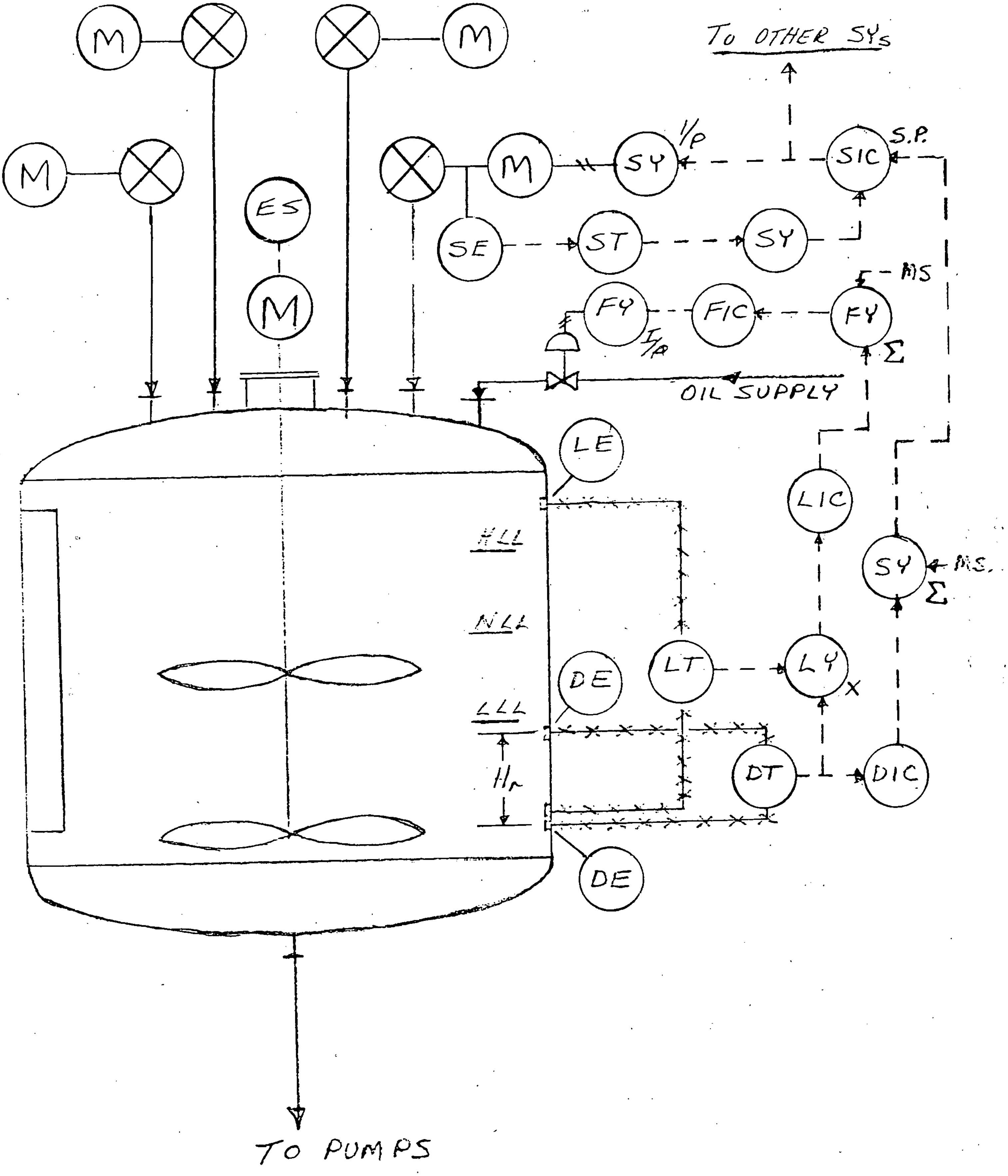
2.) "A Study of the State-of-the-Art of Instrumentation for Process Control and Safety in Large-scale Coal Gasification, Liquefaction and Fluidized-bed Combustion Systems", by Dr. N. M. O'Fallon and associates, Argonne National Laboratory under ERDA contract W-31-109 Eng-38. Final report, January, 1976.

3.) "Process Evaluation Report - Final Trade-off Studies, Future Studies - HYGAS Demonstration Plant - 1200 PSIG Case", March, 1979 by H. S. Vierk, Procon Inc. (prepared for the D O E , Division of Fossil Fuel Processing, under contract EF-77-C-01-2618).



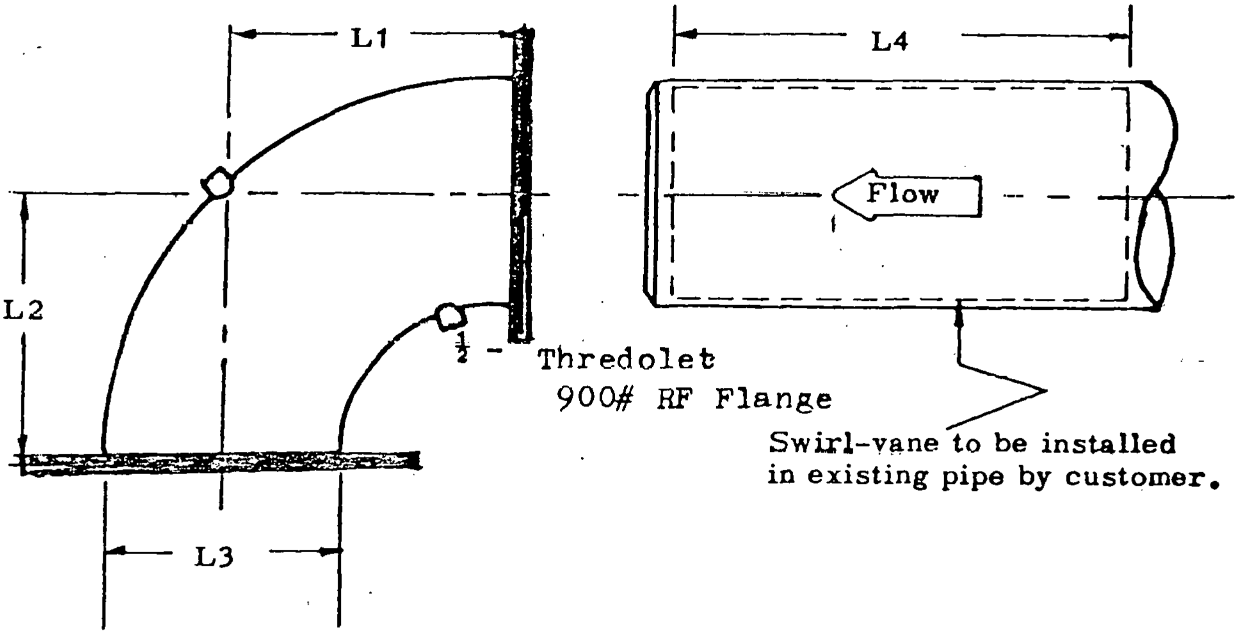
1200 PSIG CASE

PRETREATER & SLURRY MIX TANK
CONTROL SYSTEM
FIGURE 1



CHAR-OIL SLURRY MIX TANK CONTROLS

FIGURE 2



½ - Thredolet
900# RF Flange

Swirl-vane to be installed
in existing pipe by customer.

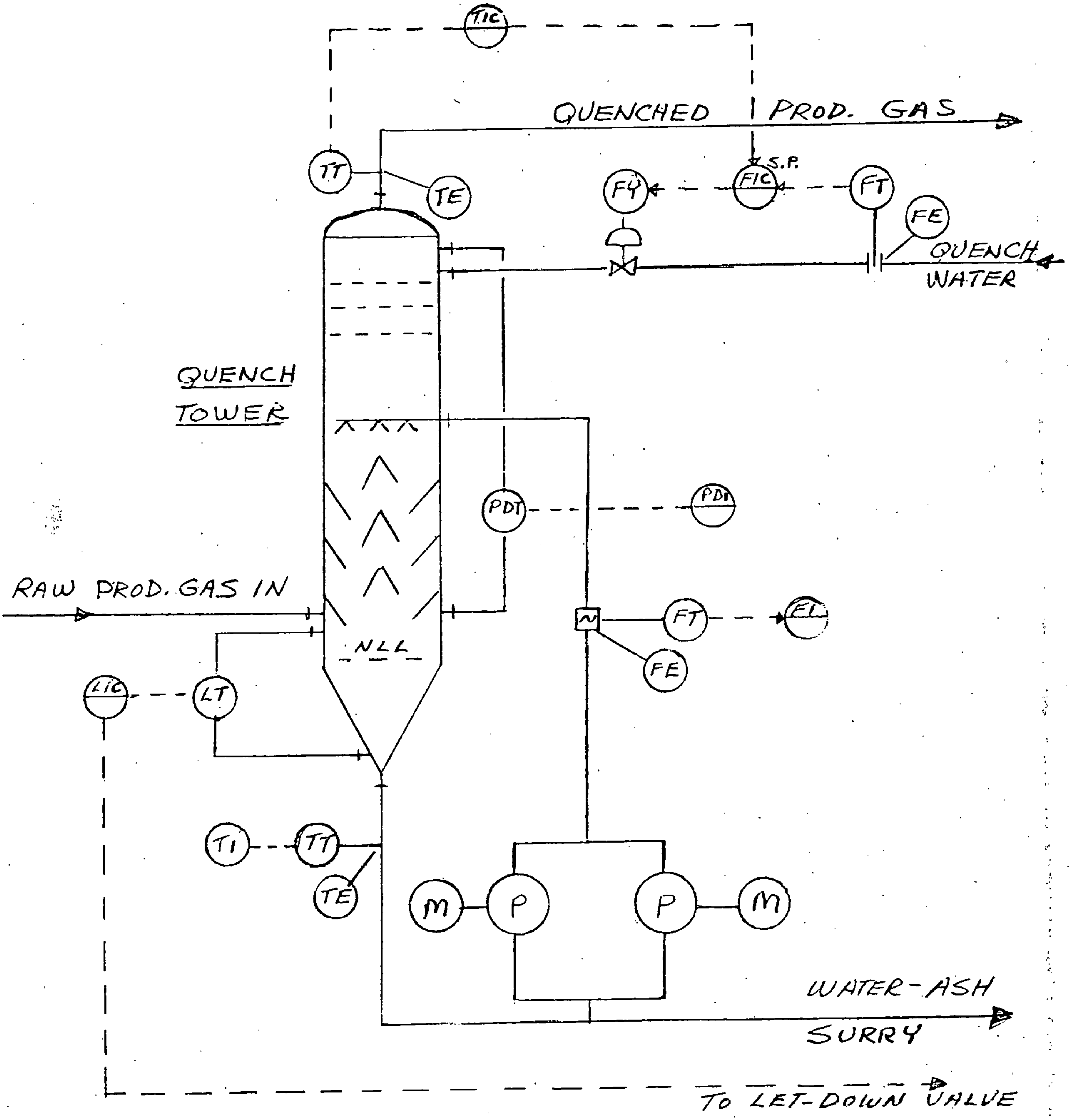
FLUID:	Coal & Oil Slurry
PRESS. RATING	1350 PSI
TEMP. RATING, °F	155
MATERIAL:	True Sched. 80/
CONSTRUCTION:	Weld
END CONNECTION:	900# R.F. Flange
VALVES:	

L_1 (INCHES)	L_2 (INCHES)	L_3 (INCHES)	L_4 inches
15"	15"		30"

PROJECT:	
CUSTOMER:	
CUST. REF:	OUR REF:
DATE:	FACT. REF:

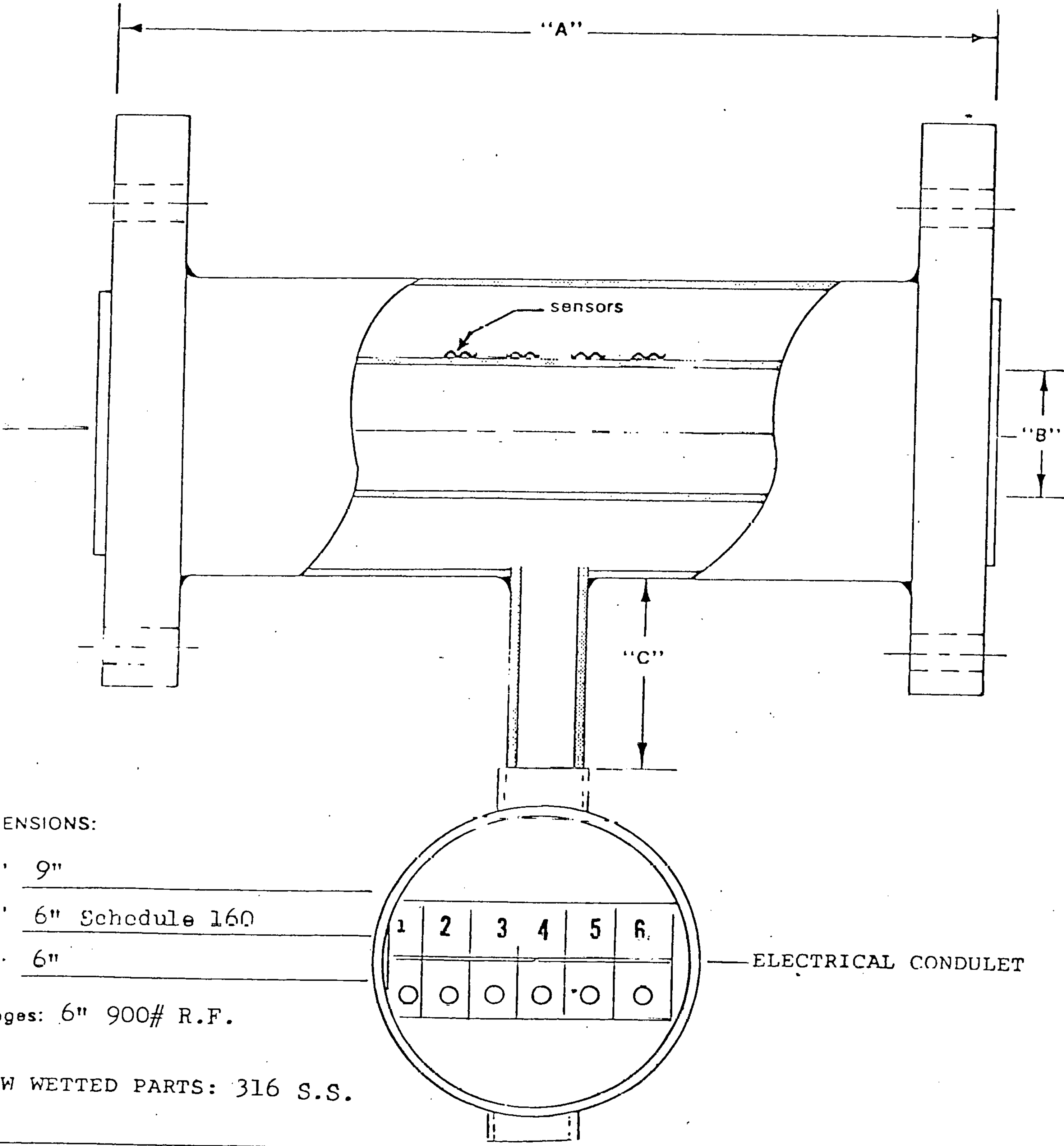
FIGURE 3

ELBOW FLOWMETER



PRODUCT GAS QUENCH TOWER CONTROLS

FIGURE 4



DIMENSIONS:

"A" 9"

"B" 6" Schedule 160

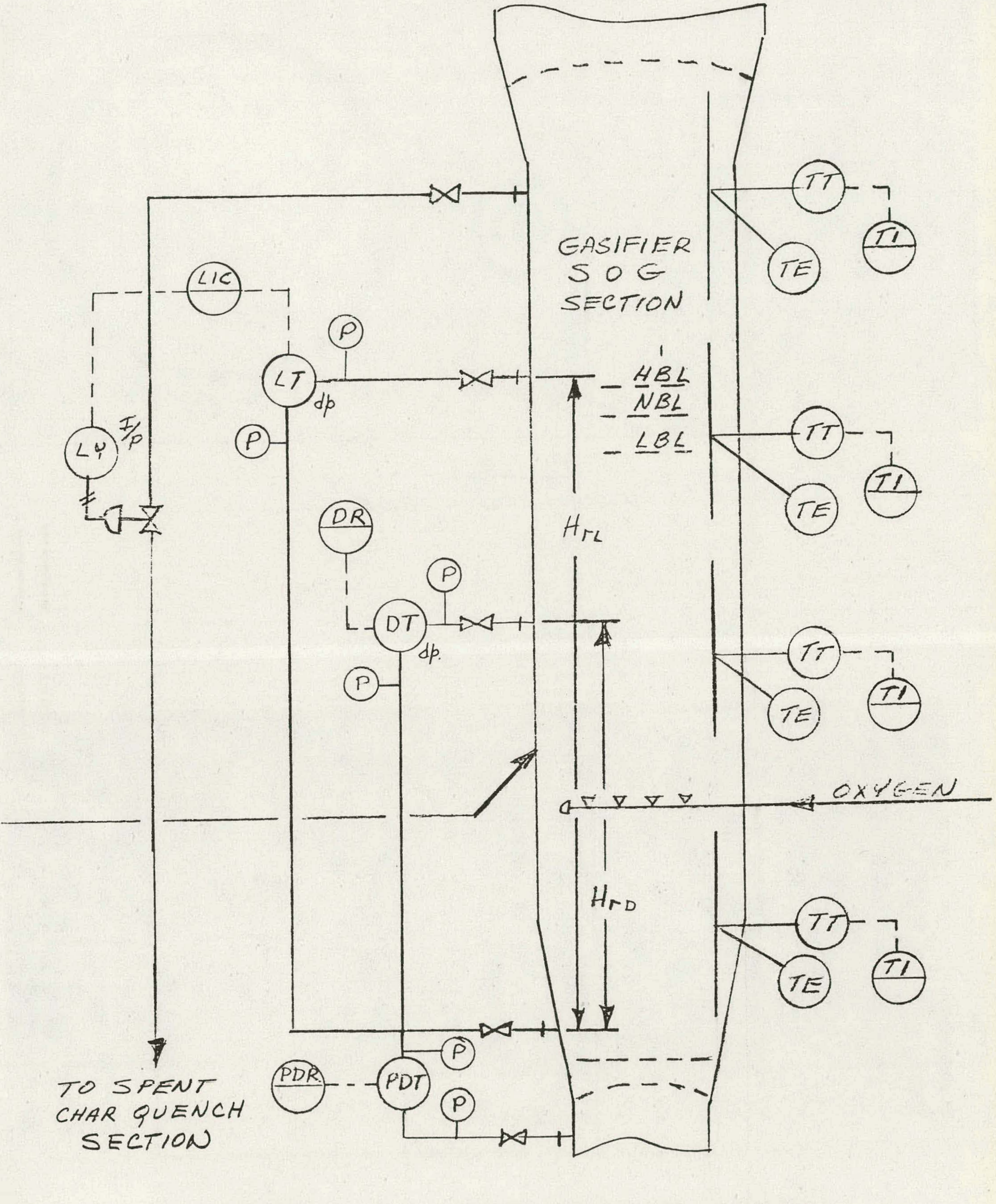
"C" 6"

Flanges: 6" 900# R.F.

FLOW WETTED PARTS: 316 S.S.

MODEL:	PHYSICAL DIMENSION DRAWING FOR EXPLOSION PROOF METER	
S/N		

FIGURE 5



GASIFIER SOG BED LEVEL CONTROL
FIGURE 6

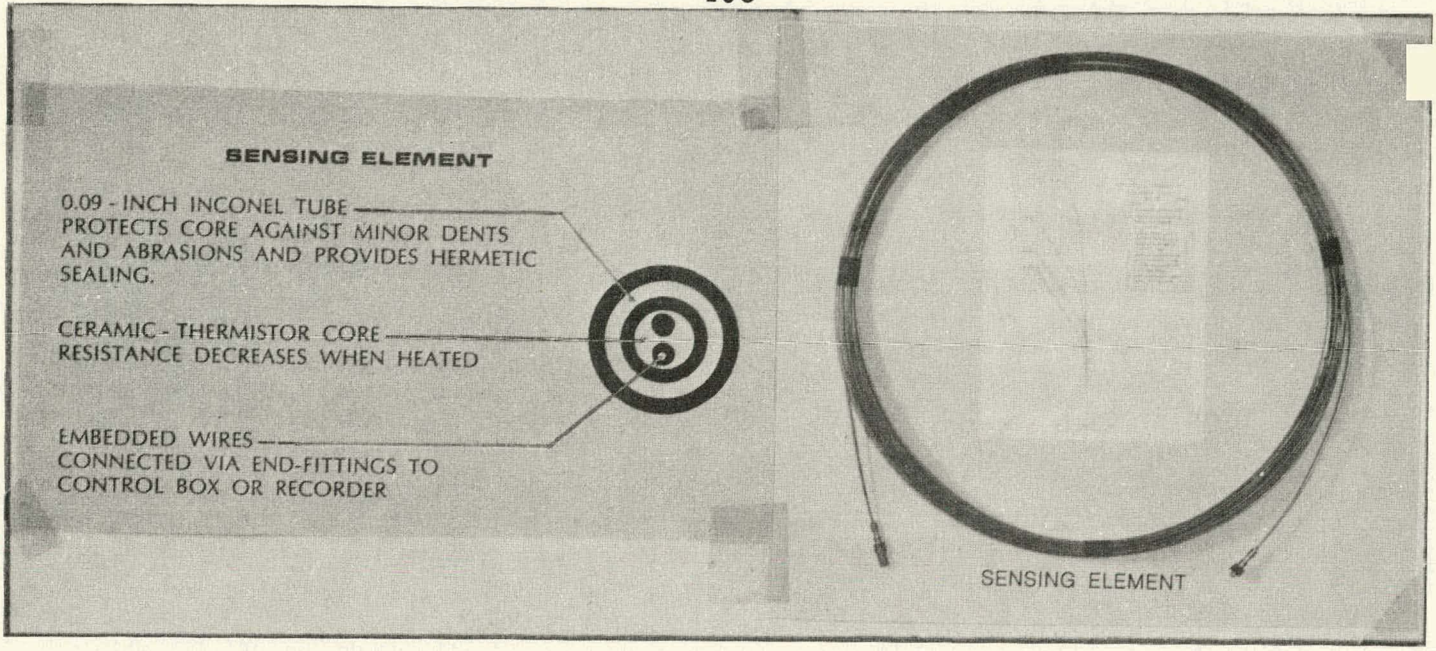
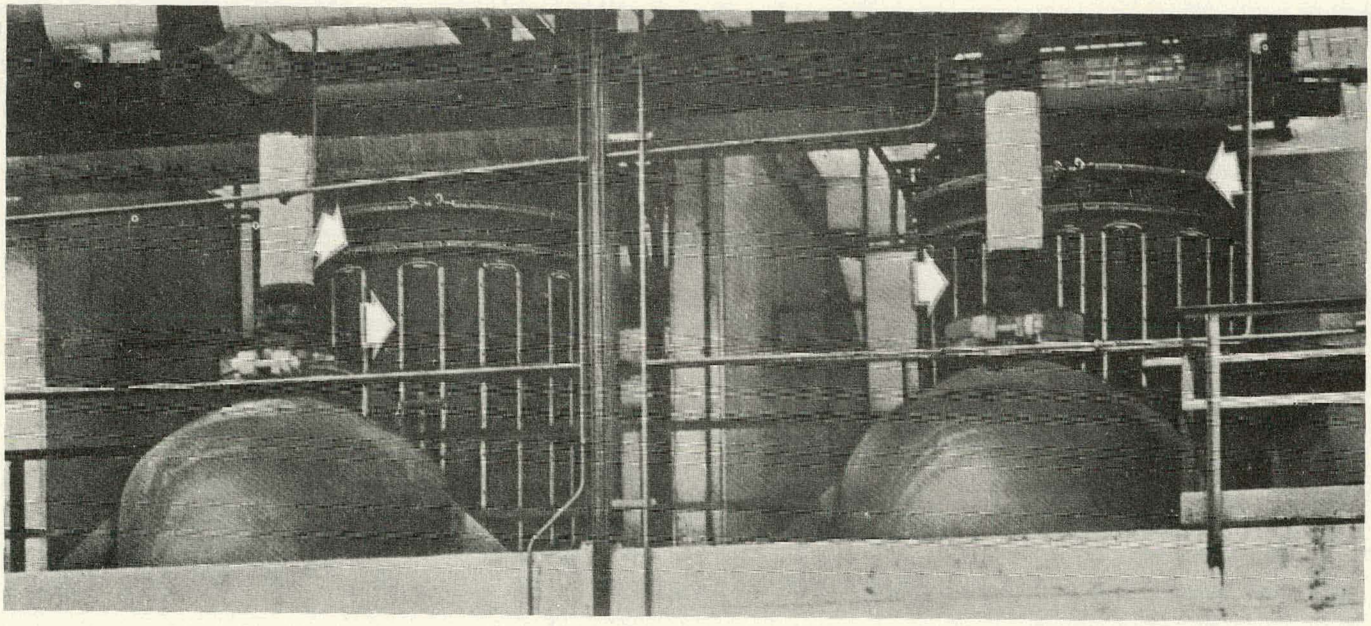


FIGURE 7

THERMISTOR SENSOR



Closeup shows overheat elements (arrows) installed horizontally and vertically on the gas generators.

FIGURE 8

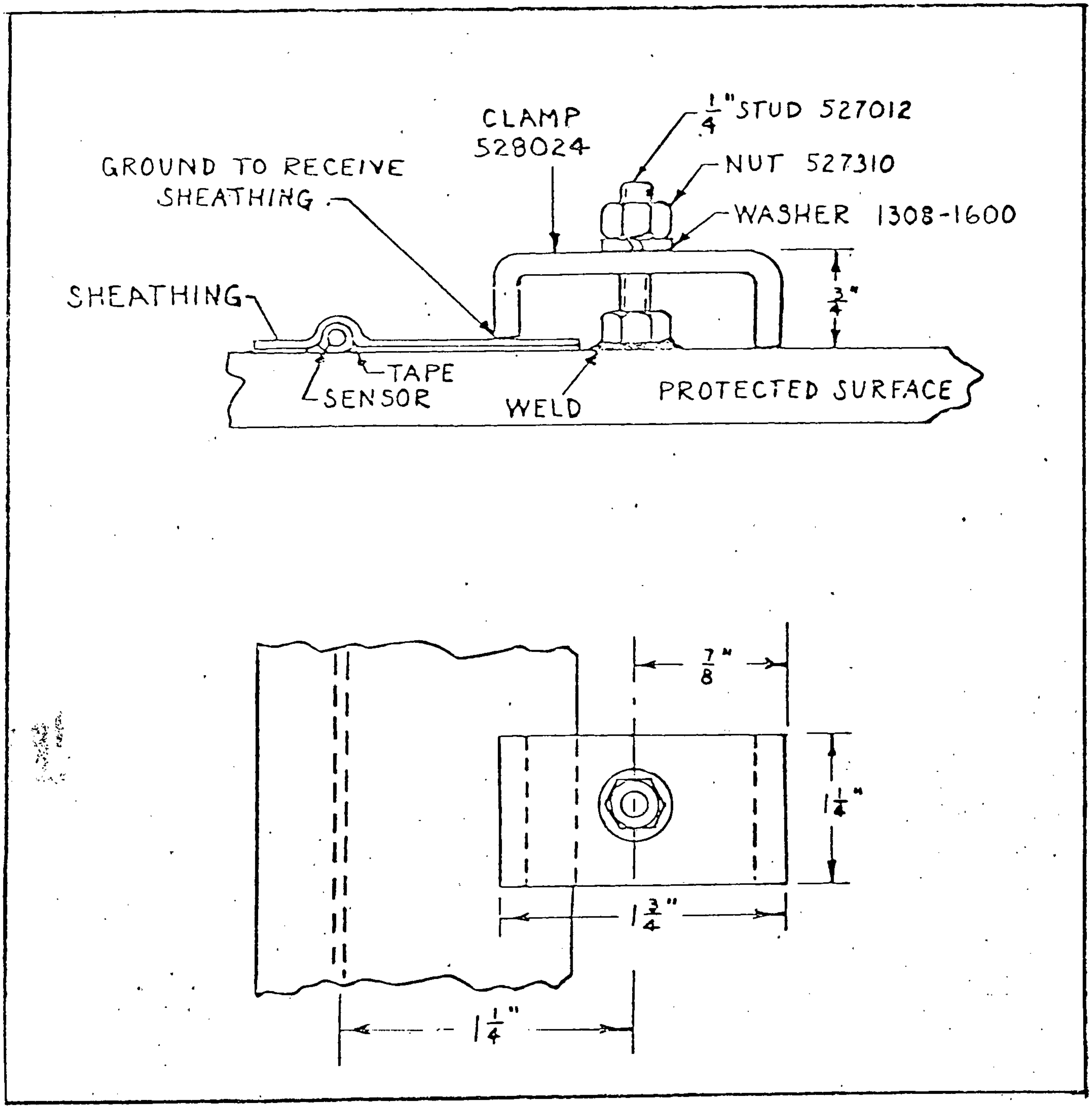


FIGURE 9
FASTENING ELEMENT TO THE SURFACE

DEVELOPMENT AND OPERATING CHARACTERISTICS OF A GAS SAMPLING SYSTEM FOR THE GRAND FORKS ENERGY TECHNOLOGY CENTER'S SLAGGING FIXED BED GASIFIER

By Douglas R. Hajicek and Leland E. Paulson
Grand Forks Energy Technology Center

INTRODUCTION

The Grand Forks Energy Technology Center (GFETC) is operating the only pilot plant sized slagging fixed bed gasifier (SFBG) in the U.S.A. It is a modified version of the Lurgi dry ash bottom process. In units of similar hearth area, the steam consumption of a slagging gasifier is about one-fourth of that required for a dry-ash unit. At the same time, the gas production is as much as three or four times that of the dry-ash gasifier.

An element of the test program is to characterize and determine production rates of gaseous and liquid effluents. A sampling system described in this paper was developed to collect tar, water and dust from the raw product gas stream. This system has successfully sampled a hot gas stream generated by gasification of high moisture low-rank coals.

GASIFICATION PROCESS

A flowsheet of the pilot plant process is shown in Figure 1. Recent publications (1,2,3,4) have discussed the test equipment and procedures in detail. A brief summary will be provided here.

The test coal is introduced into the gasifier through a single lock hopper. As the coal decends through the shaft, it is heated by counter current flow of hot gases coming from the reaction zone. Drying, devolatilization and gasification occur in distinct zones in the coal bed. The coal reacts with the steam-oxygen mixture that is injected into the hearth section. Gasification occurs at temperatures of approximately 3100°F, completely consuming the coal, leaving only molten ash. The molten ash drops down into a water bath in the lower lock hopper and is removed as slag. The product gas leaves the top of the gasifier and enters a recycle liquor spray washer where water vapors, tar, oil and dust are removed. The accumulated liquor in the spray washer system is periodically drained into an atmospheric holding tank. After passing through the spray washer, the gas is further cooled in a heat exchanger, depressurized, demisted, metered, and flared. A typical gas composition is 58% CO, 29% H_2, 5% CH_4, and 7% CO_2, with small amounts of C_2-C_4 hydrocarbons.

PROCESS VARIABLES AFFECTING SAMPLING

Most of the work reported in this paper was performed on lignite. During these tests, low ranked coals were gasified at pressures that ranged from 100 to 400 psig. The oxygen rate ranged from 4000 to 6000 scfh and the oxygen-steam molar ratio ranged from 0.9 to 1.1. Lignite moisture content ranged from 20 to 38 percent. Product gas has been sampled in 29 of the 66 gasifier runs for a total of 115 hours of sampling.

The effect of coal charging was taken into account when developing sampling procedure. In past tests, the gasifier was operated with one coal lock, which required refilling approximately every hour. Recharging the lock hopper resulted in upsets in the steady state offtake temperature, and the yield rate of water and tar produced. The steady state offtake temperature was typically 300°F when gasifying a moderately high moisture lignite. During the periodic coal charging, these temperatures varied widely from 160°F to 1000°F. Because of these periodic upsets, sampling is performed for the length of time required to gasify one or more complete charges of coal.

SAMPLING POINTS

Product gas was sampled through probes at the head of the gasifier and from the gas offtake. The sampling points are shown in Figure 2. The sampling probe at the head of the gasifier consisted of a 0.423 inch ID pipe which passed through the vessel wall and refractory into the void space above the coal bed. The sample probe at the gas offtake consisted of a ½" OD by ¼" ID tube bent into a 90° angle to face the product gas stream; the leading edge of this probe was tapered down at a 45° angle.

SAMPLER SYSTEM DEVELOPMENT

The reported sampling system evolved through several stages of development. The first sampler (Sampler I) consisted of a pressure let-down valve, four heat exchangers in series, and a wet test meter. This system was overdesigned and although difficult to operate was used successfully in a number of tests.

Experience gained with Sampler I was used in designing Sampler II which is shown schematically in Figures 3 & 4. It was designed to meet the following criteria: 1) compactness, 2) easy modification, 3) minimum internal surface area to reduce "hang-up" of tar, and 4) automatic flow control. To meet this criteria, Sampler II has the following features:

A. A high pressure cyclone, designed to withstand pressures up to 400 psig, was installed ahead of the pressure let-down control valve to remove tar and water aerosols that were causing plugging problems in the control valve.

B. A low pressure cyclone located after the control valve was used to remove residual tar, oil and water aerosols.

C. Water and light oils were condensed in heat exchangers which reduced the gas temperature to 34°F. Each heat exchanger contained 30 feet of coiled stainless steel tubing which provided adequate heat exchange surface with a minimum amount of surface area.

D. The "cryogenic trap" was added after the heat exchangers to freeze the remaining water vapor and light oils out of the gas stream. The internal construction of the trap consists of a series of baffles that increase gas residence time and increase the surface contact area. The unit is cooled by partial immersion in a mixture of acetone and dry ice.

E. Externally mounted, removable sample containers were used on each stage to allow accessibility to samples and reduce sample loss due to "hang-up" of tars.

F. The control and monitoring system is shown in Figure 4. This system consisted of an air actuated control valve, a pressure recorder-controller, a flow recorder with totalizer, an orifice assembly consisting of an orifice and differential pressure transmitter, and a temperature recorder.

SAMPLER OPERATION AND RELATED SAMPLING CONDITIONS

Sampler II has the capability to operate in different configurations and can sample from the gas offtake or the head of the gasifier. The method of sampling reported in this paper used two cyclones, two heat exchangers, and a cryogenic trap. The location of sampling was the gas offtake.

The hot product gas was drawn from the gas offtake through insulated tubing to the high pressure cyclone. The high pressure cyclone collected aerosols present at the operating pressure of the gasifier and at the temperature of the gas offtake. The cyclone was designed for an entrance velocity of 30 feet per second at 300°F and 200 psig. The pressure and temperature drop through the sample line to the cyclone was negligible. The pressure and temperature differential across the cyclone was approximately 20 psig and 5°F. A high pressure container is attached to the bottom of the cyclone to collect the sample.

The gas exiting from the high pressure cyclone passed through a pressure let-down flow-control valve and was reduced to the value set on the automatic recorder-controller. A pressure reduction to 18 psig resulted in a dry product gas flow of approximately 200 scfh through the sampler and is accompanied by a temperature drop of approximately 100°F. Previous to the installation of automatic flow-control hardware, the flow rate was controlled by manually throttling the pressure. Automatic controls have eliminated the difficulties in maintaining a steady flow that were encountered with manual controls.

From the flow-control valve the gas entered the low pressure cyclone which removed the components that were condensed during pressure reduction. Entrance velocity to the cyclone was approximately 40 feet per second at 200°F and 18 psig. The temperature differential across the cyclone was about 7°F. Sample containers at the bottom of the cyclone were attached with clamps for easy removal.

After the cyclone, the gas entered the two heat exchangers in series where additional water and light oil were condensed. The first heat exchanger which was cooled by city water reduced the gas stream temperature to approximately 60°F. The second heat exchanger is cooled by a refrigerated solution of ethylene glycol and water and reduced the gas temperature to 35°F. Both heat exchangers have quick disconnect sample containers.

The gas stream last passed through the cryogenic trap which lowered the temperature to 0°F, where the major portion of the remaining water and organics in the gas are removed. The trap could be by-passed in case of plugging.

A positive displacement meter was used to measure the total volume of gas through the system. Improvements are being made on the automatic flow monitoring and volume measurement system. This system will provide a recording of the flow rate and includes a flow totalizer with digital read-out of the volume of gas through the system.

ANALYSIS OF SAMPLES COLLECTED BY SAMPLER II

The sample from the first stage cyclone contained most of the solids and tar along with a portion of the water. The water and wet tar were separated by cooling the entire first stage sample in a dry ice-acetone bath which caused organics to sink, thus allowing the water to be decanted. The wet tar was vacuum distilled in an oil bath at a maximum temperature of 140°C to remove the water and oil. The water obtained by distillation was measured but not analyzed for trace contaminants. The material remaining after distillation included the heavy organics and solids that are classified as dry tar. The samples from stages 2, 3, and 4 contained water and light oils, which are decanted using a separatory funnel. Tars and light oils are analyzed for boiling point distributions, ultimate analysis, and organic composition by mass spec. Water fractions are analyzed for ammonia, TOC, sulfur, sulfide, pH and alkalinity. (5,6,7)

SAMPLING RESULTS

Results obtained from Test No. RA-40 will be presented as an illustration of the type of data which can be collected using Sampler II. In this test, Indianhead lignite with a moisture content of 34% was gasified at an operational pressure of 200 psig, an oxygen rate of 4,000 scfh and an oxygen-to-steam molar ratio of 1.0. The gas production rate of the gasifier was 22,000 scfh.

Operating data for the sampler is shown in Table 1. During all three test periods the low pressure cyclone (stage 1) and the two heat exchangers (stages 2 & 3) were used. The cryogenic trap (stage 4) was used in test periods 1 and 3. Samples were collected at 100, 200 and 300 scfh to determine if collection rates affect results.

The distribution of organics and water for the individual stages is shown in Table 2. Tars and oils are distributed between all four stages, with the majority in the 1st stage in test periods 1&3. In test period 2, the second stage had the majority of the organics consisting mainly of floating oil. In all three test periods, over 2/3 of the water was collected in the second stage. The cryogenic trap accounts for less than 1% of the total sample.

Table 3 shows an analysis of the aqueous fraction collected in each of the four stages from the third sample period. Results were similar for the first two sampling periods. The liquor analysis includes pH, dissolved organics (phenol, o-cresol and m,p-cresol), ammonia, sulfide and sulfur, and total organic carbon. Both individual analysis by stage and a weighted average based on total liquor collected are shown. Data indicates that the compounds are not distributed equally between stages.

Yields for tar, oil and water measured by Sampler II, are presented in Table 4. Results are given for two test periods (1 and 2). The differences in sampling rates did not significantly effect these yields.

REPRODUCIBILITY OF DATA

Comparisons between three methods of determining yields are shown in Table 5. Data for tar, water and ammonia are presented for six different runs. Yields were determined using Sampler I and II and by analyzing the total effluent generated in the spray washer during the entire run. The results for the samplers are from the first sampling period in each run. All runs were made with Baukol-Noonan lignite at an operating pressure of 200 pounds, an oxygen to steam ratio of 1.0 and an oxygen rate of 4,000 scfh. Moisture content of the feed lignite ranged from 30.0 to 37.6%.

Data in Table 5 were analyzed statistically using a two way analysis of variance without replication. Comparisons were made between sampling methods and gasifier runs at the .05 significance level. Results show no significant difference attributable to sampling method or gasification runs for ammonia, total organic carbon or tar production. Water production differed significantly between test methods but not between runs. Sampler II indicated a greater yield of water than was shown by either Sampler I or the end of run collection method.

Table 6 illustrates the reproducibility of the yields determined for tar, water, ammonia, and total organic carbon as determined by Sampler II during Run No. RA-52. Each sample period was approximately two hours, the length of time required to gasify three 1250 pound charges of Indian Head lignite. Data was not included from the fifth and seventh sampling period due to sampling and analysis problems.

The tar yield shown in Table 6 varied from 73 to 112 pounds per maf ton of coal during the different sample periods. Water and ammonia production did not vary significantly; water production ranged from 1410 to 1510 pounds and ammonia from 10.6 to 12.3 pounds per maf ton of coal. Total organic carbon increased as the run proceeded from initially 12.9 to finally 18.2 pounds per maf ton of coal.

GASIFIER MODIFICATIONS

The gasifier and supporting equipment is presently being modified for extended operation on caking and non-caking coals. Modifications include a dual coal lock hopper system to eliminate the periodic upsets caused by charging and a stirrer to permit operation on caking coals. Side stream sampling will be continued as an integral part of the program to moniter changes that occur in production rates during the duration of the test. It is expected that modifications of the sampling system will be necessary for sampling of the high temperature gas stream produced by the gasification of bituminous coal.

SUMMARY

A gas sampling system has been developed by the Grand Forks Energy Technology Center to collect the condensible portion of the raw product gas stream generated by the gasification of lignite at pressures up to 400 psig. Results have shown that this system collects a chemically representative sample, that measurements of mass production rates are reproducible, and sampling at different rates has had little effect on measurements of effluents produced.

Major components of the system are an automatic pressure control valve, a high pressure and a low pressure cyclone, two heat exchangers, a cryogenic trap, and a gas meter. Removable sample containers are used to allow accurate measurement of the quantity of sample collected. An automatic pressure control valve regulates the rate of gas sampled and reduces sample pressure to approximately 18 psig. The high pressure cyclone, located before the control valve, removes water and tar from the gas stream that could plug the control valve. The low pressure cyclone removes the additional effluents condensed out during pressure let-down.

The collection of tar and water by the cyclones indicates that these effluents are leaving the gasifier at least partly as a fine aerosol. The two heat exchangers condense out water and light oils. The cryogenic trap can be used to remove water and some of the light oils from the gas stream at temperatures below 32°F.

REFERENCES

1. Gronhovd, et al. "Design and Initial Operation of a Slagging Fixed-Bed Pressure Gasification Pilot Plant." U.S. Bureau of Mines Report of Investigations 6085.

2. Gronhovd, et al. "Slagging Fixed-Bed Gasification of North Dakota Lignite at Pressures to 400 PSIG." U.S. Bureau of Mines Report of Investigations 7408.

3. Ellman, et al. "Current Status of Studies in Slagging Fixed-Bed Gasification at the Grand Forks Energy Research Center." Ninth Biennial Lignite Symposium, Grand Forks, 1977.

4. Ellman, et al. "Slagging Fixed Bed Gasification Project Status at the Grand Forks Energy Technology Center." Tenth Biennial Lignite Symposium, Grand Forks, ND, 1979.

5. Mayer, Olson, and Schobert. "Standard Methods" for the Analysis of Coal Gasification Effluents--Caveat Emptor." National CIC Meeting, Winnipeg, 1978.

6. Olson and Schobert. "Evaluation of Methods for Determination of Sulfide in Coal Gasification Waste Water." 176th National ACS Meeting, Miami, 1978.

7. Standard Methods for the Examination of Water and Waste Water - 14th Edition published by American Public Health Association.

Table 1. - Sampler Operating Conditions - Gasifier Run No. RA-40

	Sample Periods		
	1	2	3
Length of sample period, hr.	3.0	2.0	1.9
Average sampling rate, SCF/hr	99.0	197.0	285.0
Average Temperature, °F			
Before pressure letdown	280	284	283
After pressure letdown	168	187	205
After Stage I (low pressure cyclone)	163	183	200
After Stage II (heat exchanger)	39	38	38
After Stage III (heat exchanger)	35	34	34

Table 2. - Major Sample Constituents by Stage, Gasifier Run No. RA-40

	Sampler Stage				
	I[a]	II[b]	III[c]	IV[d]	Total
Test Period 1,					
Water Collected, gms	1047	1805	97	21	2970
Tar & Oil Collected, gms	90	60	11	4	165
Total Sample, gms	1137	1865	108	25	3135
Test Period 2,					
Water Collected, gms	760	3195	52		4007
Tar & Oil Collected, gms	84	119	5		208
Total Sample, gms	844	3314	57		4215
Test Period 3,					
Water Collected, gms	780	2861	100	23	3764
Tar and Oil Collected, gms	117	44	50	4	215
Total Sample, gms	897	2905	150	27	3979

[a] low pressure cyclone
[b] heat exchangers - cooled by city water
[c] heat exchange - cooled by refrigerated solution
[d] cryogenic trap

Table 3. - Analysis of the Aqueous Phase by Stage, Third Test Period, Gasifier Run No. RA-40

	Sampler Stage				
	I[a]	II[b]	III[c]	IV[d]	average
pH	8.9	9.6	9.4	8.9	9.5
Phenol, ppm	2837	4375	4319	4068	4114
o-Cresol, ppm	351	879	850	902	790
m,p-Cresol, ppm	1024	1749	1707	1775	1627
Ammonia, ppm	1809	9455	9631	4786	8150
Sulfide, ppm	20	1650	477		1334
Sulfur, ppm	5034	3717	3536	2678	3925
TOC, ppm	5500	11000	13250	12378	10152

a/ low pressure cyclone
b/ heat exchanger - cooled by city water
c/ heat exchanger - cooled by refrigerated solution
d/ cryogenic trap

Table 4. - Yields of Condensible Components for Gasifier Run No. RA-40 as Determined by Sampler II

Test period	1a/	2
	Yield of Condensible Components, lb/ton MAF coal	
Tar	73	71
Water	1320	1370
NH_3	10.7	11.6
TOC	11.5	13.4
Sulfide	1.5	2.1
Sulfur	3.7	5.1

a/ Results include cryogenic trap.

Table 5. - Comparison of Yields as Determined by Sampler I and II and the End of Run Composite

Run No	25	26	27	29	30	31
	Yield of Condensible Components, lb/ton MAF coal					
Sampler I	55	119	81	78	97	59
Sampler II	77	104	109	83	75	90
End of Run	83	58	--	90	52	80
Water lb/ton MAF:						
Sampler I	1100	1230	1290	1250	1240	1280
Sampler II	1230	1440	1490	1330	1190	1410
End of Run	1320	1160	--	1200	1180	1140
Ammonia lb/ton MAF:						
Sampler I	7.1	10.8	10.7	8.8	11.9	13.2
Sampler II	12.4	12.6	12.4	11.3	11.6	13.6
End of Run	12.5	11.4	--	--	11.1	--
Total organic carbon lb/ton MAF:						
Sampler I	8.8	9.2	8.9	10.0	9.6	11.6
Sampler II	11.5	10.7	11.1	12.1	9.3	13.3
End of Run	13.5	12.3	--	---	10.9	--

Table 6. - Yields by Test Period as Determined by Sampler II for Gasifier Run No. RA-52

	Yields of Condensible Components, lb/ton MAF coal			
Test Period	Tar	Water	Ammonia	TOC
1	73	1410	10.7	12.9
2	84	1460	11.1	14.4
3	84	1460	12.3	15.4
4	95	1510	11.5	16.4
5	--	--	--	--
6	112	1460	11.0	17.0
7	--	--	--	--
8	90	1450	10.6	16.1
9	109	1500	11.8	18.2

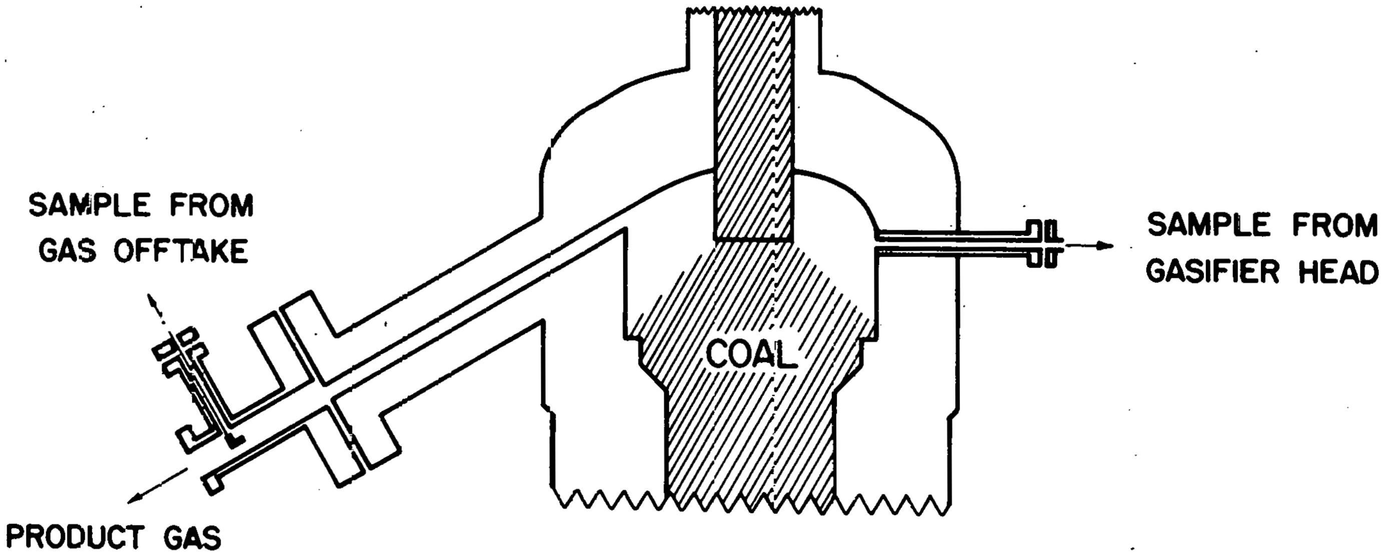
LIST OF FIGURES FOR THE PAPER:

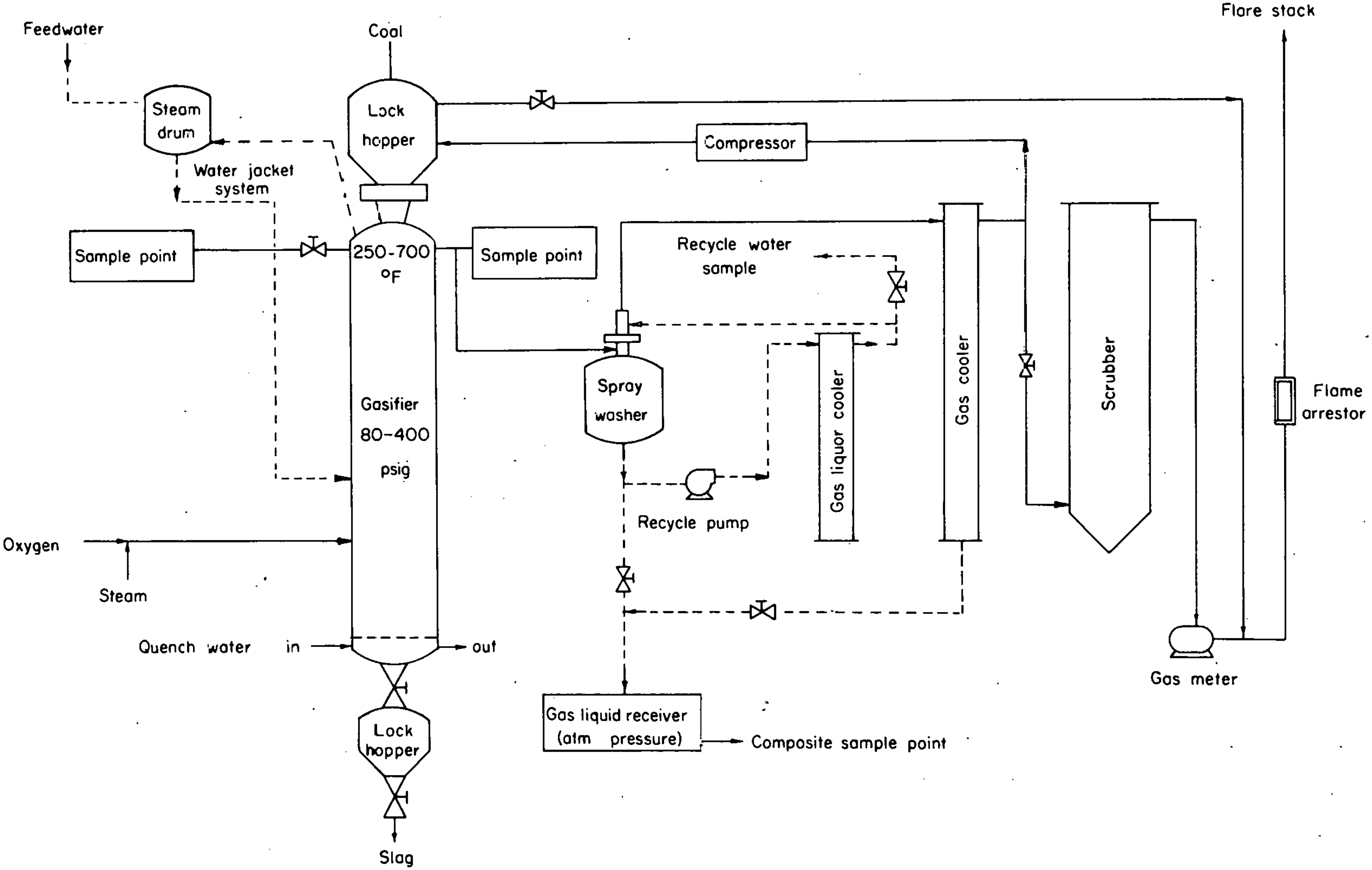
"Developing and Operating Characteristics of a Gas Sampling System for the Grand Forks Energy Technology Center's Slagging Fixed-Bed Gasifier"

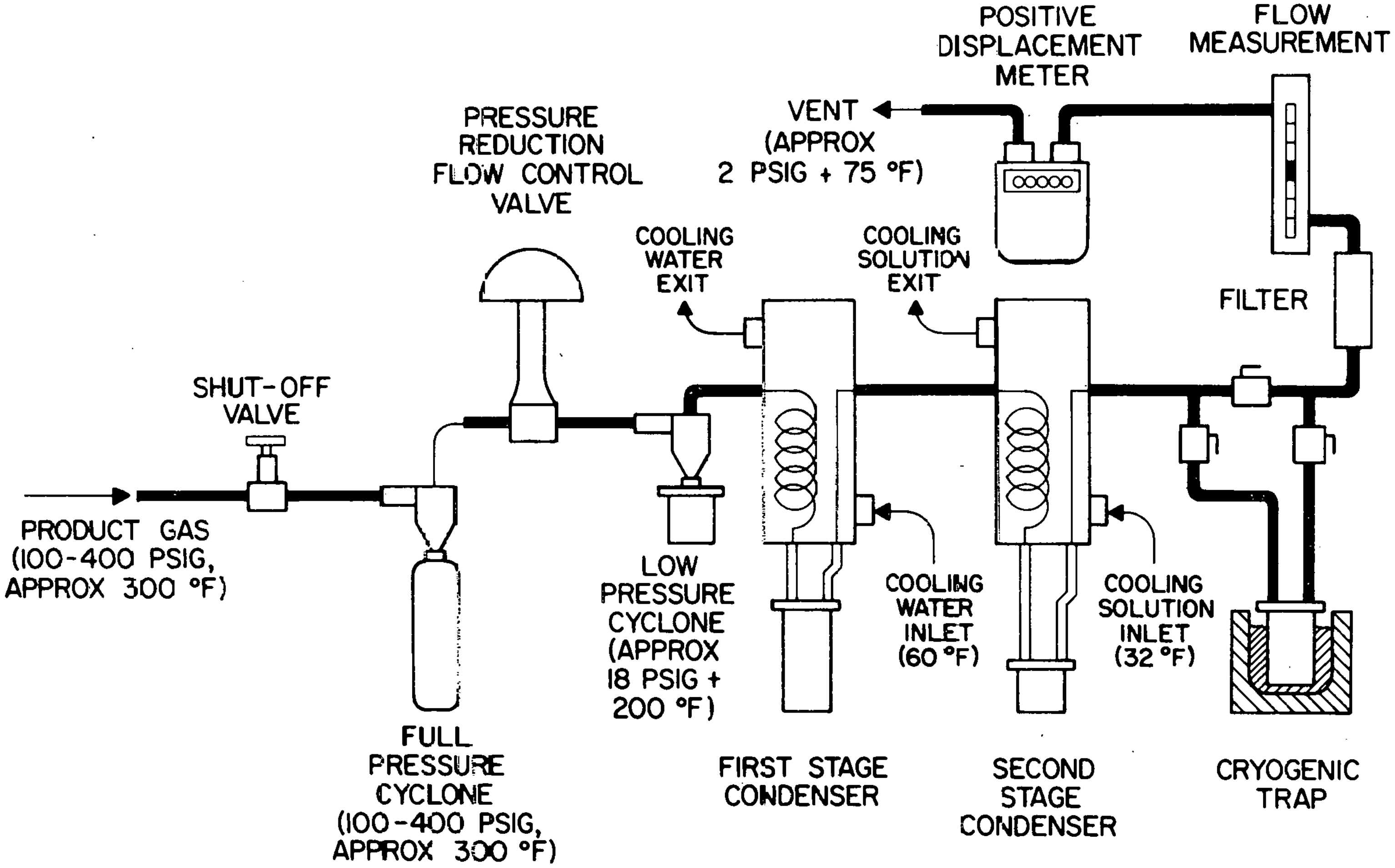
by

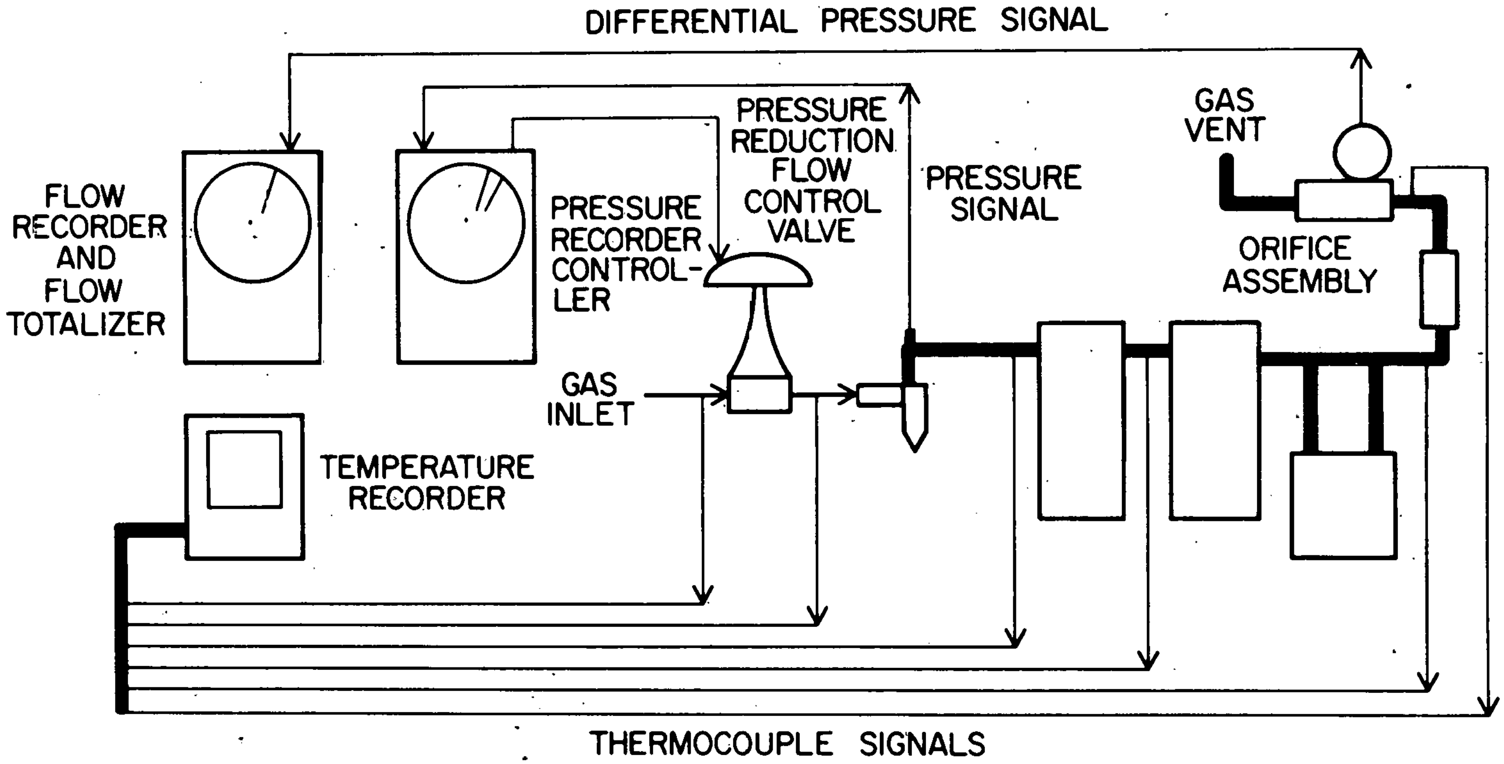
D. R. Hajicek and L. E. Paulson

GASIFIER HEAD AND SAMPLING LOCATIONS




Feedwater
Coal
Flare stack
Steam drum
Lock hopper
Compressor
Water jacket system
Sample point
250-700 °F
Sample point
Recycle water sample
Gas cooler
Scrubber
Flame arrestor
Spray washer
Gas liquor cooler
Gasifier 80-400 psig
Recycle pump
Oxygen
Steam
Quench water in
out
Gas meter
Lock hopper
Gas liquid receiver (atm pressure)
Composite sample point
Slag


PRODUCT GAS (100-400 PSIG, APPROX 300 °F)
SHUT-OFF VALVE
FULL PRESSURE CYCLONE (100-400 PSIG, APPROX 300 °F)
PRESSURE REDUCTION FLOW CONTROL VALVE
LOW PRESSURE CYCLONE (APPROX 18 PSIG + 200 °F)
COOLING WATER EXIT
COOLING WATER INLET (60 °F)
FIRST STAGE CONDENSER
COOLING SOLUTION EXIT
COOLING SOLUTION INLET (32 °F)
SECOND STAGE CONDENSER
CRYOGENIC TRAP
FILTER
FLOW MEASUREMENT
POSITIVE DISPLACEMENT METER
VENT (APPROX 2 PSIG + 75 °F)



DIFFERENTIAL PRESSURE SIGNAL
PRESSURE REDUCTION FLOW CONTROL VALVE
GAS VENT
FLOW RECORDER AND FLOW TOTALIZER
PRESSURE RECORDER CONTROL-LER
PRESSURE SIGNAL
ORIFICE ASSEMBLY
GAS INLET
TEMPERATURE RECORDER
THERMOCOUPLE SIGNALS

PARTICULATE SIZE MEASUREMENTS USING LIGHT SCATTERING TECHNIQUES

James C. F. Wang and Daniel Tichenor
Sandia Laboratories, Livermore

1. ABSTRACT

Particle size distribution measurements using a small-angle near-forward light scattering (SANFS) arrangement have been found to be a promising technique for applications in combustor environments and advanced power systems. In this paper, characteristics of the light scattering response for this optical arrangement are discussed in detail based on Mie theory calculations. Preliminary data from a bench-scale experiment and a means to improve measurement accuracy are reported.

2. INTRODUCTION

Particulate emission control is one of the most challenging tasks in recent developments of advanced fossil fuel combustion systems. Size distribution, dust loading density, and other critical physical and chemical properties of particulates in the effluents of combustors and their associated cleanup equipment comprise the key information needed for the development. However, there has been a lack of accurate and real-time particulate diagnostic techniques for the effluents from advanced power systems. This has prevented efficient evaluations of the performance of combustors and cleanup equipment and has made it difficult and complicated to develop and modify components in the advanced power systems to meet environmental regulations and gas turbine product specifications. There is thus a need, manifest and urgent, for appropriate particulate diagnostic instruments, especially those with capabilities of nonintrusive, in situ, and real-time monitoring. The difficulties which challenge the instrument designers originate from the hostile environment of most advanced fossil fuel combustion systems.

Presently, particle diagnostic techniques can be grouped into two categories: physical sampling techniques, and optical techniques. The physical sampling technique has been used extensively by industry and utility companies to characterize the effluents from their boilers or furnaces. It is the only means of providing collected samples of particles for the detailed analyses of their physical and chemical properties. These measurements, however, may be biased or dubious because of the inherent shortcomings associated with the sampling process.[1] It is intrusive, for example, and requires time consuming off-line data analyses. Due to condensation, agglomeration and chemical reaction in the probe the sample collected may not represent what is in the measured flow. Thus, a real-time, nonintrusive, and in situ particulate diagnositc technique is required to complement the measurements by the physical sampling technique and even to replace it in some applications.

In principle, both optical scattering and photographic (including holographic) techniques can provide nonintrusive measurements of particle size and/or number loading density. The photographic methods, nevertheless, also require off-line data analysis which is usually tedious and time consuming.[2] For real-time monitoring capability, the optical techniques appear as the most promising candidates. There are, however, many assumptions and statistical interpretations involved in relating the measured optical signal to the size and number density of the particles. The accuracy of the measurements by optical methods depends on how much is known a priori about the particulates and the flow environment and how good are the assumptions related to a particular application. The high-temperature, high-pressure, and high-dust-loading conditions encountered in almost every fossil fuel combustion system provide further challenges to the designers of optical particle counters for real-time, in-situ measurements.

The objective of this paper is to demonstrate the capability of a small-angle near-forward scattering (SANFS)[3] optical arrangement for particle size measurements in combustor exhausts. Single particle scattering measurement is emphasized because it can provide accurate size distribution information, rather than only the mean particle size, as with most multiple scattering techniques. One should keep in mind, however, that there is no single instrument expected to satisfy the entire size or composition range of interest or application anticipated in combustor environments and advanced power systems.

3. LIGHT SCATTERED BY A SPHERE

When light strikes a particle, a portion of the light energy is absorbed and the rest is scattered by the particle or its surface irregularities. The extent of the absorption and scattering depends on the wavelength of the incident light, λ, and the nature of the particle (e.g., its refractive index m, radius r, and shape). For a sphere of radius comparable or large relative to the wavelength of the incident light, the light scattering pattern can be predicted by Mie theory.[4] The Mie function is an exact solution to Maxwell's wave equation for the scattering of electromagnetic radiation by a spherical particle. It consists of a series of spherical harmonic terms with the coefficients containing the refractive index and size parameter, $\alpha = 2\pi r/\lambda$, of the particle.

For unit-intensity incident light polarized in the directions perpendicular or parallel to the scattering plane, the expressions for the scattered light intensity are, respectively:

$$I_1 = \frac{\lambda^2}{4\pi^2 r^2} |S_1 (\Theta, m, \alpha)|^2 \sin^2 \phi , \qquad (1)$$

$$I_2 = \frac{\lambda^2}{4\pi^2 r^2} |S_2 (\Theta, m, \alpha)|^2 \cos^2 \phi , \qquad (2)$$

where S_1 and S_2 are complex amplitude functions of the Mie scattering functions and are sums of spherical Bessel functions of the first and second kind. A sketch of the Mie scattering geometry is shown in Figure 1. The scattering plane is the plane containing the incident light ray (direction of propagation) and the scattering vector; ϕ is the azimuthal angle propagation) and the scattering vector; ϕ is the azimuthal angle measured from the plane of polarization to the scattering plane and Θ is the scattering angle measured from the direction of propagation to the direction of observation in the scattering plane. The Mie theory is quite general in that it is applicable on the one hand to particles in the Rayleigh region ($r \ll \lambda$) and on the other hand to large particles up to the size where classical geometric optics can be applied. It is applicable to both absorbers and dielectrics. Figure 2 shows typical Mie scattering polar plots. The first lobe in the forward direction is called the Fraunhofer diffraction lobe. The oscillatory pattern versus scattering angle is one of the characteristics of Mie scattering phenomena. The pattern changes as a function of particle size, refractive index, shape, etc., and is used as a means to measure particle size in some applications.[5]

For very small particles ($r < 0.1\ \lambda$), the Mie function simplifies to yield the Rayleigh equation.[6] It is usually written in the following form for unpolarized light:

$$I = \frac{8\pi^4}{R^2} \frac{m^2-1}{m^2+2} \frac{r^6}{\lambda^4} (1 + \cos^2 \Theta) , \tag{3}$$

where I is the intensity of light scattered by a sphere of radius r at an angle Θ to the incident light beam. R is the distance from the particle to the point of observation; I is composed of two polarized components with intensities I_1 and I_2. Figure 3 shows a typical Rayleigh scattering pattern from a particle of 0.1 μm diameter. The intensity of the vertically polarized light, I_2, is the first term in the last bracket and represents a uniformly distributed pattern from 0° to 360°. The intensity of the horizontal polarized light, I_1, peaks in the forward (0°) and the back (180°) scattering directions and is zero at 90°. The Rayleigh scattering intensity shows a sixth power dependence on the radius of the particle. As the size of the particle decreases, the scattered light becomes undetectable very quickly. Thus, scattering from a group of these small particles has to be used instead of the scattering from a single particle.

4. SMALL-ANGLE NEAR-FORWARD SCATTERING (SANFS) ARRANGEMENT

Light scattered by a sphere in the forward small angles, i.e., within the forward Fraunhofer diffraction lobe, exhibits some unique characteristics which are necessary to the particle size measurement in combustion environments. First, the scattering intensity response versus particle size is a monotonic function instead of the oscillatory one at angles outside the Fraunhofer lobe. Figure 4 shows a comparison of the Mie scattering responses as functions of particle size at various scattering angles. The monotonic behavior of the scattering response at the small-angle near-forward direction provides accurate size identification over a wide dynamic range in particle sizes. The Fraunhofer diffraction lobe, however, becomes narrower as the particle size increases. For a fixed forward small-angle scattering arrangement, the monotonic response breaks down for particles whose Fraunhofer lobe becomes smaller than the angle of scattering (e.g., particles 15 μm in diameter and larger for 2° scattering angle; see Figure 5). At scattering angle of 0.5° and the incident light wavelength of 0.514 μm, the upper useful limit on particle size is about 60 μm diameter. Ideally, the upper particle size limit can be scaled according to the size parameter, α, and the collection angle. For large particles, however, it becomes difficult to collect scattered light at small angles in the forward direction and avoid the incident light beam simultaneously when there are turbulence and temperature fluctuations in the flow.

The second characteristic of the SANFS arrangement is the insensitivity of the scattering response to the refractive index of the particle. Figure 5 shows typical responses of a SANFS arrangement at 2° angle from particles of a wide range of refractive indices. For comparison, scattering responses from similar particles at 45° scattering angle is shown one Figure 6. The nearly collapsed response curves at the SANFS arrangement are essential to ensure accurate size measurement of particles anticipated in the combustor environments where the chemical and physical properties of the particulates are not known a priori. This characteristic of the scattered light within the Fraunhofer diffraction lobe has been verified experimentally[7] and is widely recognized.

The scattered light response in the forward Fraunhofer diffraction lobe is also demonstrated as being least sensitive to the shape and orientation of the particles.[8,9] Isometric particles (i.e., those with no great inequalities among their different dimensions) of many shapes have scattering patterns similar to spheres of equal volume.[10] Figure 7 shows calculated variations in scattering responses based on the same projected area for a SANFS arrangement for particles whose shape in the direction of the incident light beam is square, rectangular, or circular. Agreement among these responses from different-shaped particles are excellent at small sizes and deteriorates as the particle size increases. The deviation, however, at 50 μm is estimated to be only about 15%, which is better than the measurement error encountered in most cases. For scattering at angles larger than the Fraunhofer diffraction lobe, theoretical predictions similar to the Mie function have not been established for irregular-shaped particles. However, limited calculations on spheroid particles were reported recently and showed a strong dependence in the scattering pattern on shape and orientation of the spheroid.[11,12] In addition, the shape and orientation of particulates encountered in most combustor environments and advanced power systems, are irregular and are expected to change from one instant to the next. The insensitive response to the particle shape from a SANFS arrangement is essential to ensure any measurement accuracy on particle sizes in the industrial combustion environments.

The useful measurement range on particle size using a SANFS arrangement can be extended at a reasonable forward scattering angle by employing a light source of multiple wavelengths. The oscillatory behavior from particles whose Fraunhofer diffraction lobe becomes narrower than the scattering angle of the collector can be smoothed with an incident light source containing a white spectrum or selected wavelengths.[3] Figure 8 shows a typical calculated Mie scattering response at scattering angles of 0.57° to 5.7° using three wavelengths from a typical argon-krypton ion laser, namely 0.647, 0.514, and 0.488 μm. A nearly monotonic relation between the scattered light intensity and the particle diameter up to 100 μm can be approximated.

There are, however, problems associated with the SANFS arrangement as well. First, the low-angle collection in the forward direction causes the depth of view along the incident light beam to be longer than that in other off-axis collection arrangements. Without proper coincidence detection, a typical length of the depth of view can be on the order of 5 mm, depending on the collecting lens and size of the aperture in front of the photodetector. This makes it impractical in a high-dust-loading environment to make single-particle measurements. However, a simple optical logic arrangmeent can be implemented to check the position of the particle with respect to the focal point of the collection lens.[13] An improved logic detection system is shown in Figure 9. The SANFS signal from the scattered light is obtained at the photodetector PD1 through the annular aperture. The measuring volume seen by PD1 is shown as V_1, which is long due to the small angle collection geometry. The photodector's signal has to be validated by the logic outputs from photodetectors PD2 and PD3.

The signal from PD3 represents the light scattered at a larger angle (outside the annular aperture on the collecting lens of PD1). The effective measuring volume seen by PD3 is shown as V_3 in the lower right corner of Figure 9. If the particle passes through the measuring volume V_1 but outside V_3, the output from PD3 will be "off." By establishing a logic coincidence check, the signal from PD1 is accepted only when PD3 is also "on." The effective measuring volume of PD1 is reduced to V_3. The depth-of-view of the SANFS arrangement can be reduced to 100 μm or less along the incident beam.

Another problem results from the fact that the scattered light intensity from a particle depends on the intensity of the incident light at the location of the particle. The intensity of a well collimated white light beam or a laser usually has a Gaussian distribution across the cross section of the beam. If only the average incident light intensity is monitored, the scattered light intensities measured from a small particle at the center of the beam (high incident intensity region) and a large particle at the edge of the beam (low incident intensity region) will be similar. Thus, a serious ambiguity in particle size determination based on the absolute scattered intensity is introduced. This is called the "edge effect" or "nonuniform intensity" ambiguity. An illustration of the edge effect is shown in Figure 10. For the same scattering intensity measured, the size of the particle can be a range of values depending on where it is located in the scattering volume. Without proper correction for this effect, the measurement accuracy on particle sizes cannot be defined.

Various means for overcoming this ambiguity have been proposed and exercised in some applications.[14-16] The edge effect ambiguity can be minimized optically by using PD2 in the same logic detection arrangement shown in Figure 9. The signal from PD2 represents the light scattered at the same small angle geometry as PD1, but through a smaller size aperture. By reducing the size of the aperture A2 in front of the detector PD2, one can use the output from PD2 as a logic sensor to accept only those particles passing through the center of the scattering volume (V_2), i.e., PD2 is "on." An illustration of the effective measuring volume cross section is shown in the lower right corner of Figure 9. By combining the logic coincidence check of PD2 and PD3, the signal from PD1 is accepted only when both PD2 and PD3 are "on." An effective scattering volume of 10^{-6}cm^3 with minimal edge effect ambiguity can be easily achieved.

5. Experimental Setup

A bench scale experiment has been assembled at Sandia Livermore to test the concept of the small-angle near-forward scattering arrangement. Figure 11 is a picture of the experiment; Figure 12 is a schematic. Since a monodispersed particle generator is used at present, the logic coincidence check arrangement is not implemented in the experiment. The light source is a 5-mw He-Ne laser, whose beam is focused to approximately 60 µm diameter at the measuring volume. The incident beam intensity I_0 is monitored by a photodiode from the light split before the focusing lens. The collecting optics consists of a mask, a collecting lens, a 50-µm-diameter pin hole, a narrow-band interference filter, and a photomultiplier. The mask provides a transparent ring of 4.5 mm ID and 5 mm OD centered along the incident light beam axis. The inner mask serves as the light dump for the incident light. The transparent ring on the mask and the distance of the mask from the measuring volume defines the angle of collection, which is set to be 0.5° ± 0.03°. An aperture is located at the focal point of the collection lens to minimize the size of scattering volume and the background light.

Two monodispersed particle generators have been used for the calibrated particle source for the bench test. The TSI model 3050 Berglund-Liu vibrating orifice aerosol generator provides monodispersed liquid droplets of 10 to 40 µm and solid particles of 1 to 10 µm. The PMS-Model PG-100 particle generator can produce monodispersed latex polystyrene particles at low number density in the range of 0.05 to 3 µm. The two generators together can provide a wide range of particles of different size and index of refraction to verify the Mie scattering responses of the SANFS optical arrangement.

A block diagram of the data acquisition and analysis procedure is shown in Figure 13. The essential data management center is the PDP11/34 minicomputer. The measured intensities of the incident and the attenuated light, I_0 and I_A respectively, are stored in the memory of the minicomputer via a constant A/D sampling process. The ratio I_A/I_0 is computed and stored continuously with the light scattering data. The signatures of the scattered light from particles passing through the measuring volume are detected by an RCA 33000A photomultiplier and digitized by a Nicolet Model 204 digital scope. The digitized signatures are then transferred to the minicomputer which constructs histograms of the ratio of signature pulse height to incident light and the particle transient time (pulse width of the particle signature). The histogram of particle size is constructed from the pulse height histogram by deconvoluting the measured laser beam incident intensity distribution at the measuring volume.[16] Particle velocity is obtained from the histogram of the particle transient time.

Parallel to the Nicolet digital recording of the particle signature in real time, a Traco Northern pulse-height analyzer is used to establish an on-line pulse height histogram of particle signatures. This is used as a real-time particle-size distribution monitor. The actual particle size information can be obtained by storing the pulse-height histogram on the PDP11 minicomputer and processing the data through the same deconvolution procedure for the Nicolet off-line scope recorded data.

6. PRELIMINARY TEST RESULTS

Droplets of about 30 and 50 μm diameter were generated from the Berglund-Liu generator and sent separately through the SANFS scattering volume. The liquid used in the test was isopropyl alcohol. The nearly stationary diffraction pattern obtained for each test indicated that the droplets were monodispersed. Figure 14(a) shows a picture of the typical 50-μm-diameter diffraction pattern obtained with a light dump placed in front of the camera. The monodispersity of the droplets was also confirmed by the SANFS measurements as shown in Figure 15. The oscilloscope trace in Figure 15 shows the output signal from the photomultiplier directly. Each negative pulse represents a signature of the droplet traversing through the focal point of the laser beam. The almost equal amplitude pulses indicates the size of the droplets were nearly equal. The pulse frequency agrees with the vibration frequency of the orifice which broke up the liquid jet to form droplets.

When smaller droplets were generated by adjusting the orifice vibrating frequency, vertical fringes were observed and superimposed on the circular diffraction pattern. Figure 14(b) shows a typical fringe-diffraction pattern of droplets at about 30 μm in diameter. These vertical fringes are evidence of having two droplets in the scattering volume simultaneously. The laser beam diameter at the scattering volume was about 60 μm and the separation between droplets was approximate the diameter of the droplets. For droplets of about 30 μm in diameter, two consecutive droplets are inevitably inside the laser beam. In addition, these vertical fringes are in the direction perpendicular to the droplet velocity. The contrast of the fringes became enhanced and the fringe spacing increased when the size of the droplets decreased.

7. VARIABLE FREQUENCY GRID TECHNIQUE

Although the SANFS arrangement can be extended for particle size measurements up to 100 μm in diamter, the Mie scattering response becomes less sensitive and oscillatory (Figure 8). An alternate method for sizing particles in the range of 10 μm and up is being investigated. This technique is related to the particle sizing interferometer[14,17] in which the particle diameter is determined by the fringe visibility observed in a laser doppler velocimeter. By adjusting the angle between the two crossed beams of the velocimeter the interferometer can operate over a wide range of particle diameters. However, for a given beam angle the dynamic range is limited to about one decade due to ambiquities that arise at low fringe visibility.

The variable frequency grid technique,[18] described here, seeks to extend the range of particle sizes that can be measured without realignment by introducing a range of fringe spacings. One of several optical arrangements that employs this principle is shown in Figure 16. The measurement volume is illuminated by either a laser or white light source, and an image of the particle is cast onto a variable frequency grid. As the image of the particle scans across the grid, the transmitted light signal (Figure 17) oscillates with varying visibility and goes through a null in visibility at a well defined point approximately where the particle diameter equals the local grid spacing. Since the grid spacings are known, the particle diameter can be determined by the position of the first null in visibility.

The transmitted light signatures were simulated by scanning the grid of Figure 17 with a circular aperture having a diameter approximately equal to the width of the first dark grid line (Figure 18a). A circular aperture one third of this diameter was used to generate the signature of Figure 18b. The visibility in Figure 18b remains much higher at smaller grid spacings. However, the visibility nulls are not clearly shown due to obvious imperfections in the grid. A simple envelope detection and extrapolation technique can be implemented to measure the first null, thus providing an accurate identification of the grid location and particle size.

Several other optical arrangements can be used to implement the variable frequency technique. A central stop can be used in front of the lens to cast a schlieren image of the particle onto the grid. In the case of diffuse particles the measurement region can be illuminated from the right in Figure 17, thereby removing the DC component due to direct light from the source. Illumination at right angles to the viewing direction offers the ability to eliminate out of focus particles by illuminating the measurement region only. An arrangement similar to the interferometer technique is obtained if a real image of the grid is projected in the measurement region. This can be done either by the use of an imaging lens or by holography. Finally, an off-axis zone plate, the spatial equivalent of a linear chirp, can be generated at the measurement region by interfering a plane wave and a spherically focused beam. The best arrangement may depend on the particular application. In any case signatures similar to those of Figure 18 will be generated with each of these configurations.

8. CONCLUSIONS

Particulate diagnostics using the optical light scattering principle can provide an on-line real-time monitoring of particle size distribution in gaseous or liquid flows. For a medium with particles of a broad range of sizes, shape, composition, and mass loading density such as those generally encountered in a fossil fuel combustion system, the small-angle near-forward scattering arrangement appears to be the most appropriate candidate among various optical arrangements. The Mie scattering response is found to be least sensitive to the refractive index and shape of the particle within the forward Fraunhofer diffraction lobe. The response curve is also found as a monotonic function of particle size up to 60 μm diameter at a reasonable SANFS arrangment. By introducing a multiwavelength light source, the useful dynamic range of particle size can be extended to 100 μm or larger.

Based on the limited data from the bench scale experiment, the measured scattering signature pattern from the SANFS arrangement agreed with the droplet behavior from the generator. The absolute intensity calibration to the size of the droplet is currently underway and will be checked against the Mie calculation. The optical logic control will be implemented to advance the SANFS apparatus further toward a prototype instrument for industrial use.

The variable frequency grid technique was demonstrated to be feasible based on the simulation test results. Experiments using pulverized coal particles in the size range of 20 to 200 μm in mean diameter will be performed on the laboratory bench in the near future.

9. REFERENCES

1. Vitols, V., "Theoretical Limits of Errors Due to Anisokinetic Sampling of Particulate Matter," J. Air Pollution Control 16, 79 (1966).
2. Holtham, G. A., "Sizing Aerosals in Real Time By Pulsing UV Laser

Machine," in The Proceedings of a Seminar on Aerosal Measurements, edited by W. A. Cassatt and R. S. Maddock, (NBS Special Publication 412), p. 97 (1974).

3. Wang, J. C. F., "Optical Particulate Size Measurements Using A Small-Angle Near-Forward Scattering Technique," Sandia Report SAND79-8246 (1979).
4. Mie, G., "Beitrage Zur Optik Truber Medien Speziell Kolloidaler Mattalosungen," Ann. der Physic 28, 377 (1908).
5. Sinclair, D. and La Mer, V. K., "Light Scattering As a Measure of Particle Size in Aerosals," Chem. Rev. 44, 245 (1949).
6. van de Hulst, H. C., Light Scattering By Small Particles, John Wiley & Sons, Inc., New York, NY (1957).
7. Hodkinson, J. R., "Particle Sizing by Means of the Forward Scattering Lobe," Appl. Optics 5, 839 (1966).
8. Ellison, J., McK., "Extinction of Light By Suspension of Silica," Proc. Phys. Soc. B70, p. 102 (1957).
9. Hodkinson, J. R., "Light Scattering and Extinction by Irregular Particles Larger than the Wavelengths," Proc. Interdisciplinary Conf. Electromagnetic Scattering, p. 87, edited by M. Kerker, Pregammon Press, Oxford (1963).
10. Hodkinson, J. R., "The Optical Measurement of Aerosals," Aerosol Science, Chap. X, edited by C. N. Davis, Academic Press, New York, NY (1966).
11. Latimer, P., Brunsting, A., Pyle, B. E., and Moore, C., "Effects of Asphericity on Single Particle Scattering," Appl Optics, 17, 3152 (1978).
12. Jones, A. R., and Wong, W., "Direct Optical Evidence for the Presence of Sooty Agglomerates in Flames," Combustion and Flame 24, p. 139 (1975).
13. Knollanberg, R. G., "An In-Stack Fine Particle Size Spectrometer: A Discussion of Its Design and Development," Proceedings: Advances in Particle Sampling and Measurement, Asheville, NC (May, 1978),

EPA-600/ 7-79-065, p. 169 (1979).

14. Bachalo, W. D., "Particle Field Diagnostics Systems for Fluidized Bed Comustion Facilities," Proceedings of the Fifth International Conference on Fluidized Bed Combustion, Vol. III, edited by C. Bliss, p 362 (1977).
15. Faxvog, F. R., "New Laser Particle Sizing Instrument," International Automotive Engineering Congress and Exposition, Detroit, MI, (Feb. 28-March 4, 1977), paper 770140 (1977).
16. Holve, D. and Self, S., "An Optical Particle-Sizing Counter for In-Situ Measurements," Applied Optics, 18, 1632 (1979).
17. Roberds, D. W. "Particle Sizing Using Laser Interferometry," Applied Optics, 16, p. 1861, (1977).
18. Fristrom, R. M., Jones, A. R., Schwar, M. J. R., and Weinberg, F. J., "Particle Sizing by Interference Fringes and Signal Coherence in Doppler Velocimetry," Faraday Symposia of the Chemical Society 7, p. 183 (1973).

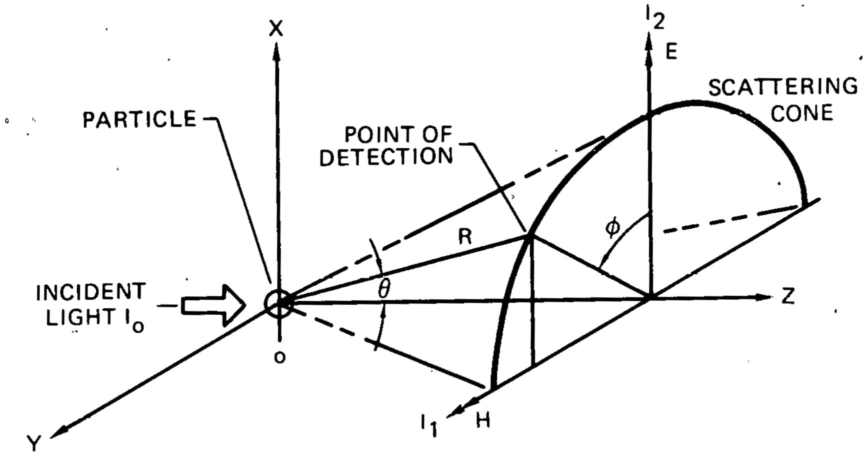


Figure 1. Schematic Of Light Scattering Geometry

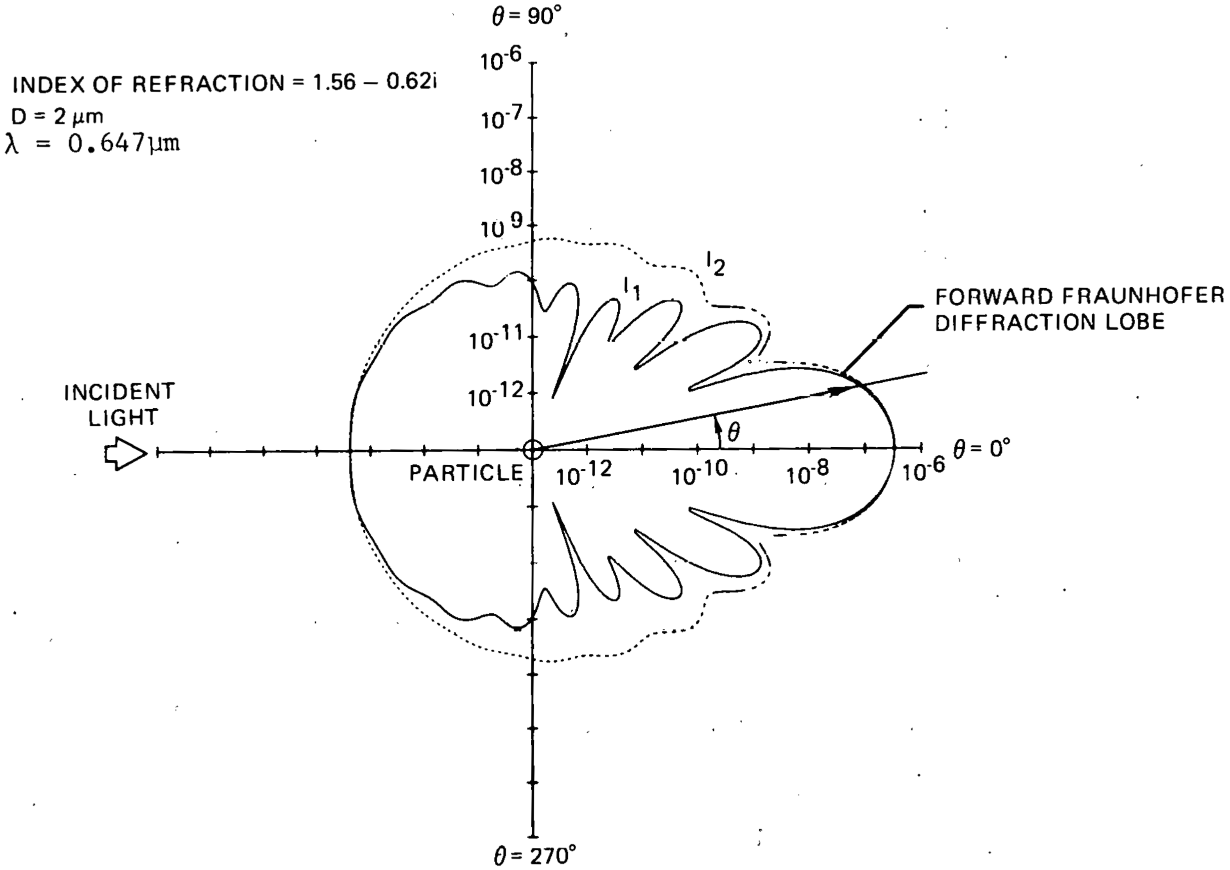


Figure 2. Typical Mie Scattering Intensity--Polar Plot

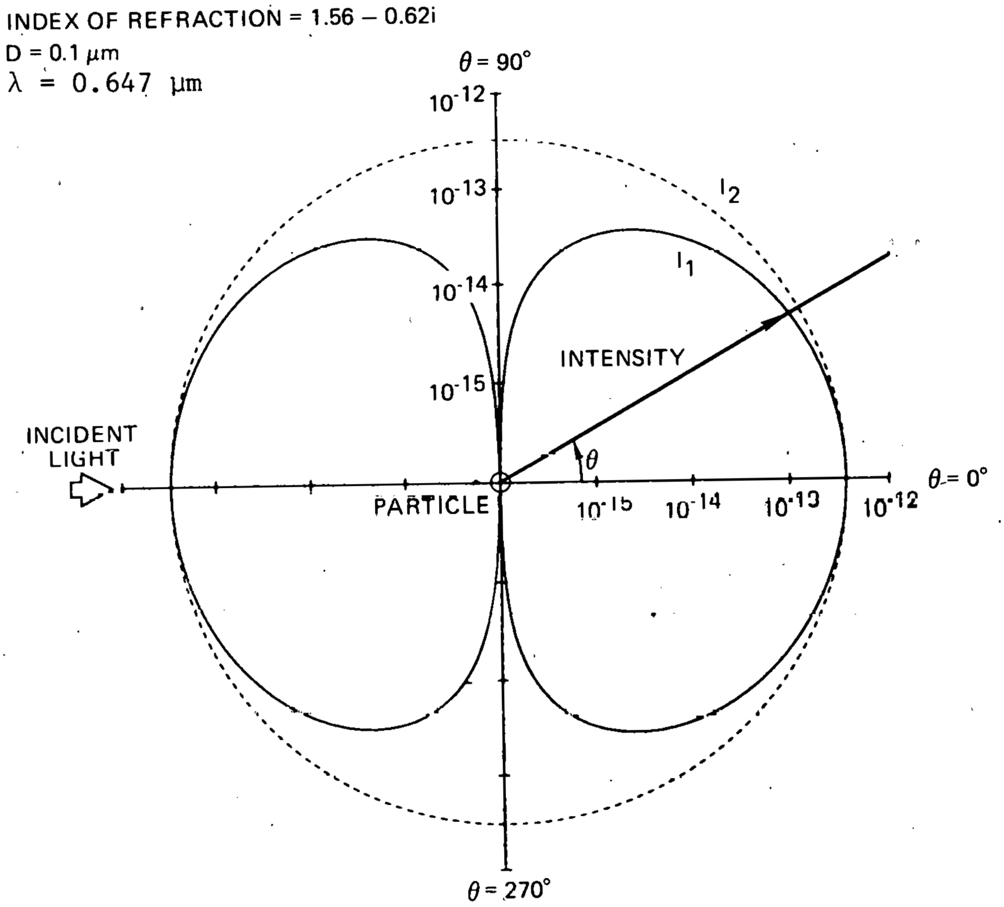


Figure 3. Typical Rayleigh Scattering Intensity Pattern

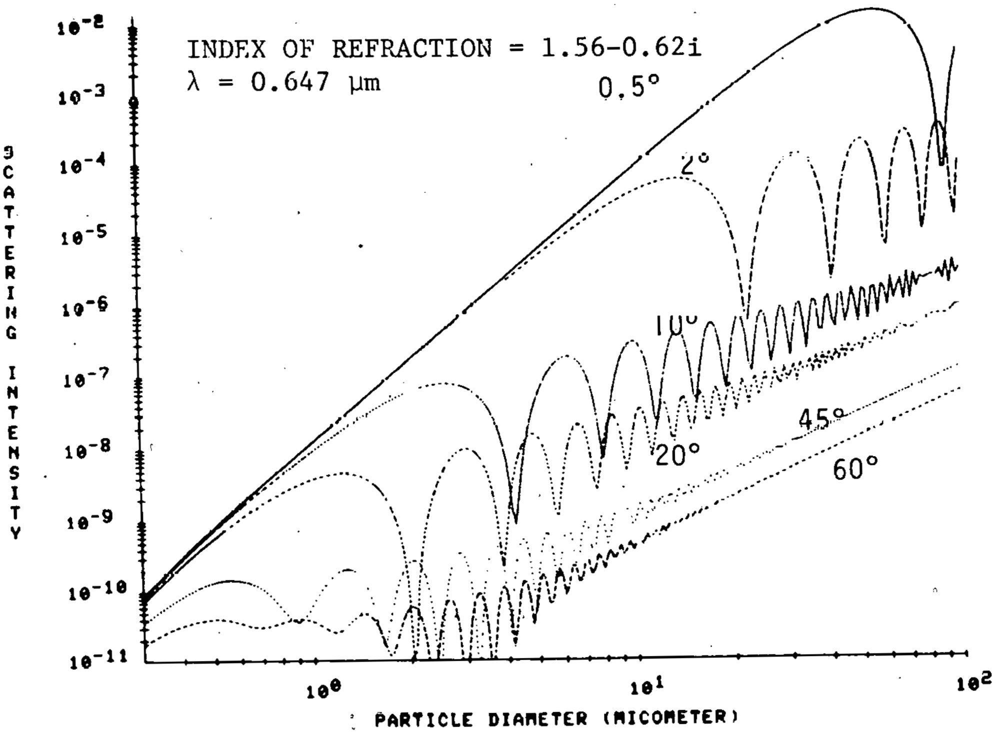


Figure 4. Calculated Mie Scattering Responses At Various Scattering Angles

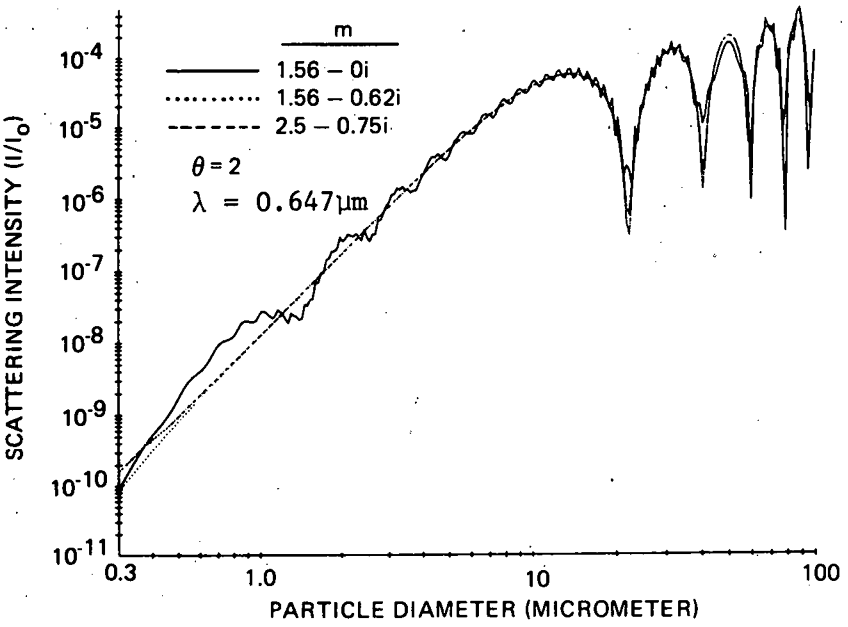


Figure 5. Calculated Mie Scattering Responses At Θ = 2°

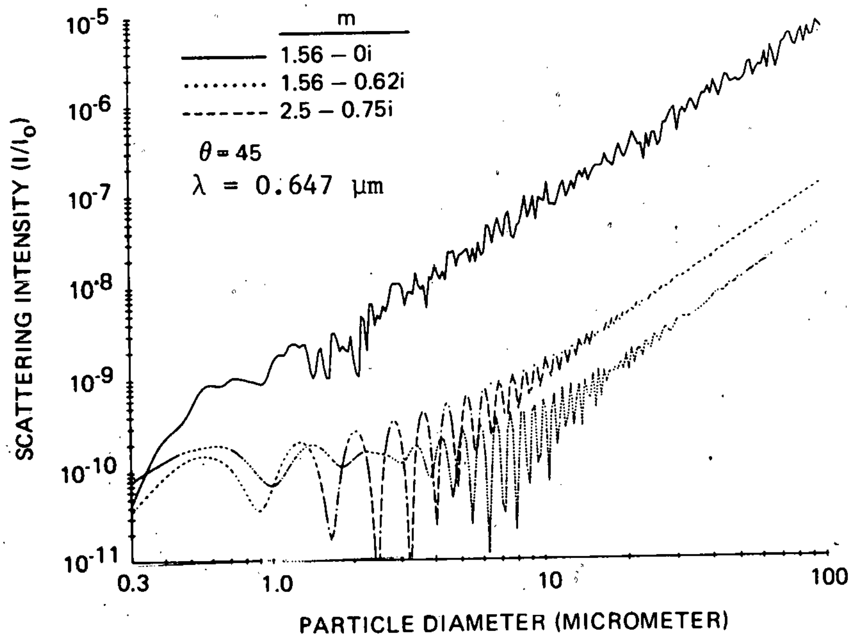


Figure 6. Calculated Mie Scattering Responses At Θ = 45°

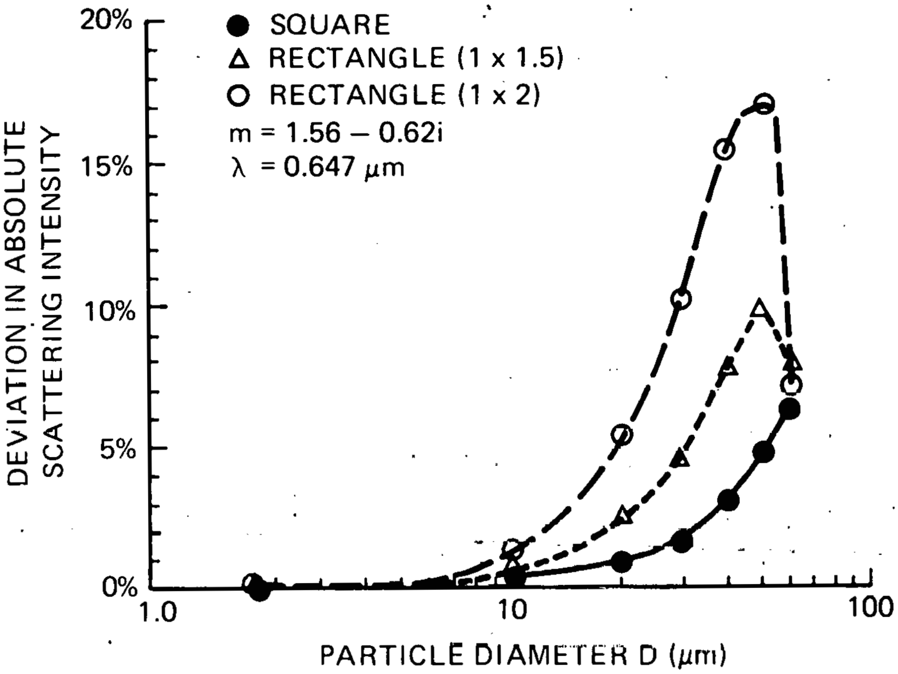


Figure 7. Effect Of Particle Shape On SANFS Responses

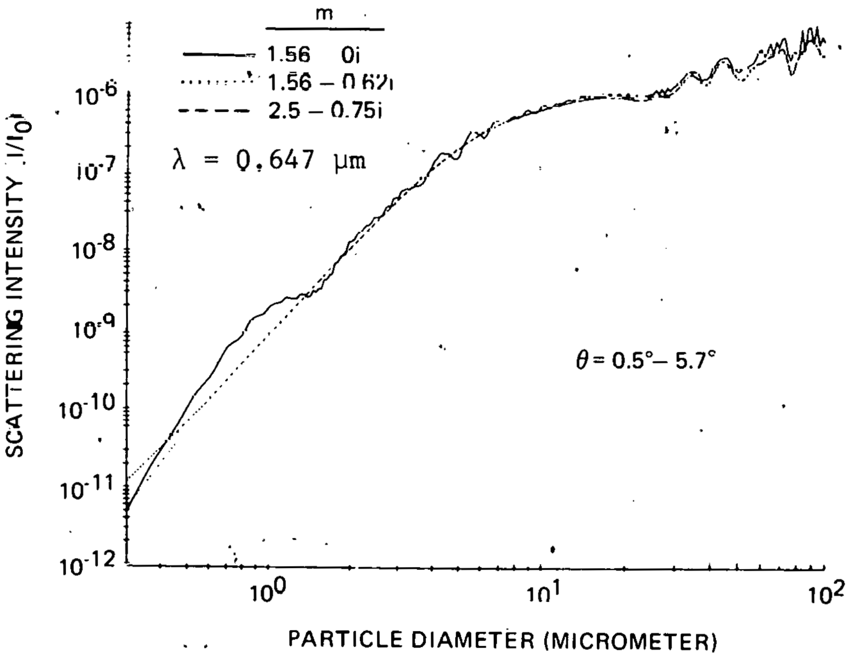


Figure 8. Calculated Mie Scattering Responses Using Multiple Wavelengths

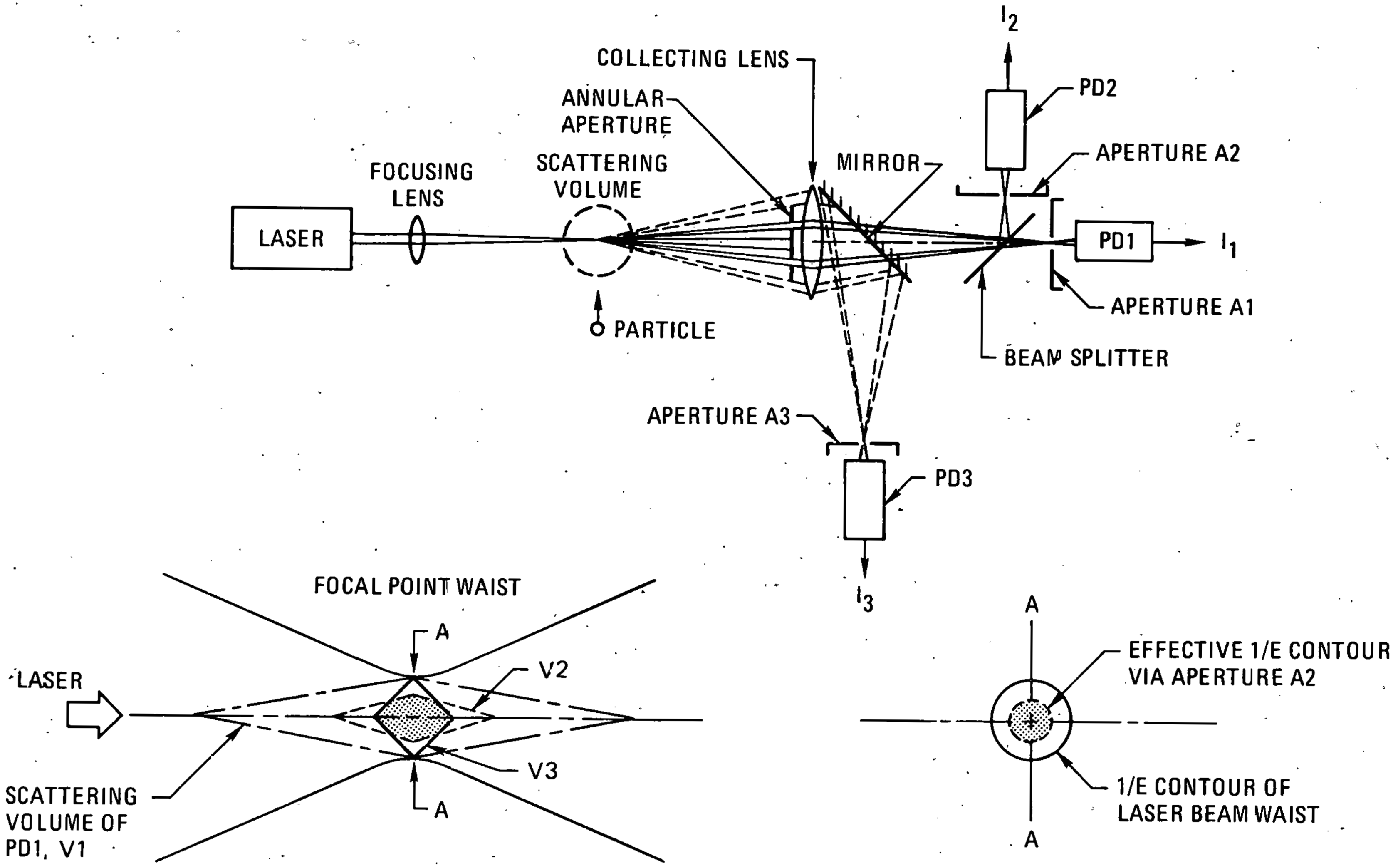


Figure 9. Schematic of Optical Logic Arrangement for SANFS Technique

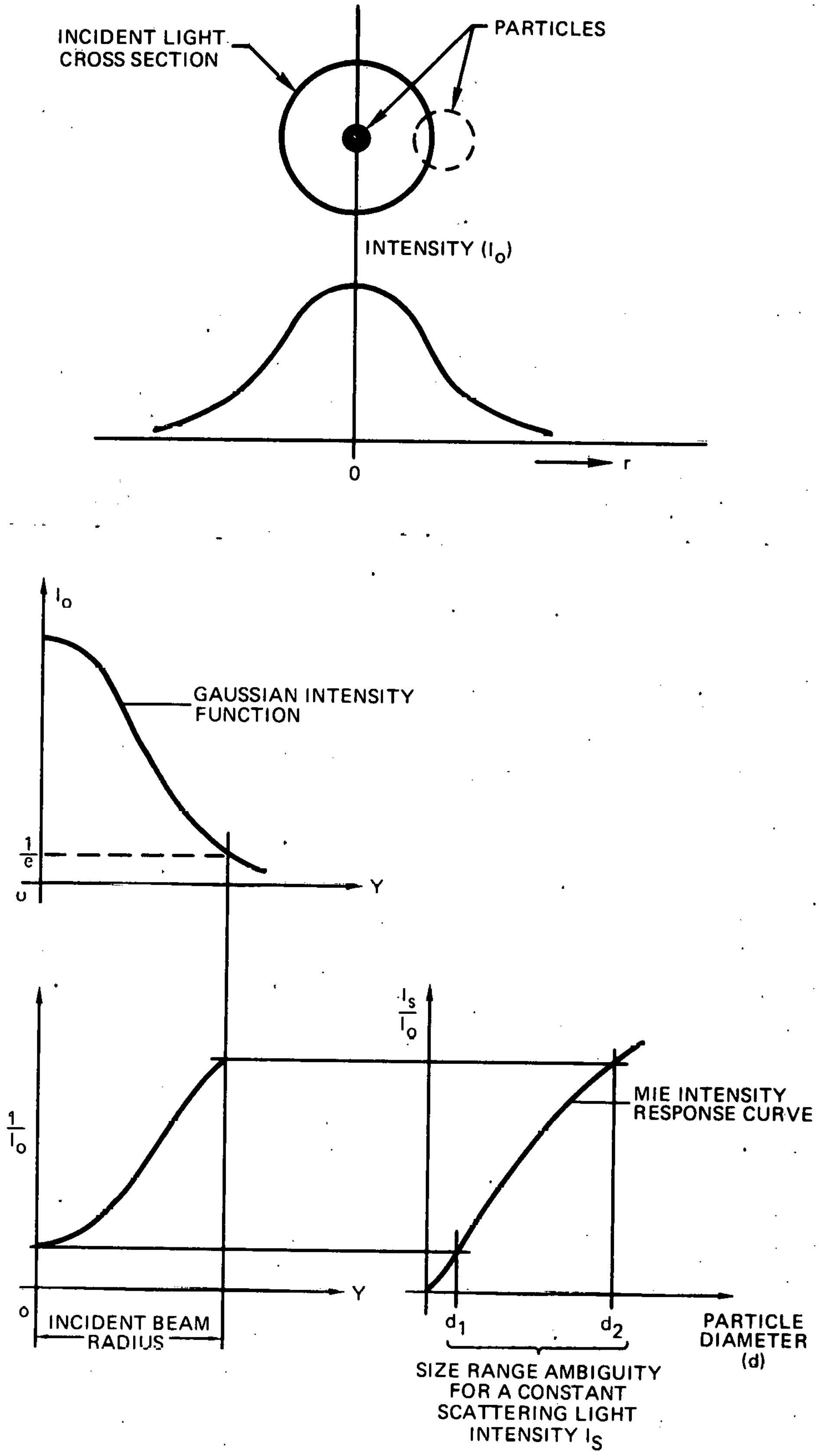


Figure 10. Size Ambiguity Due To Edge Effect

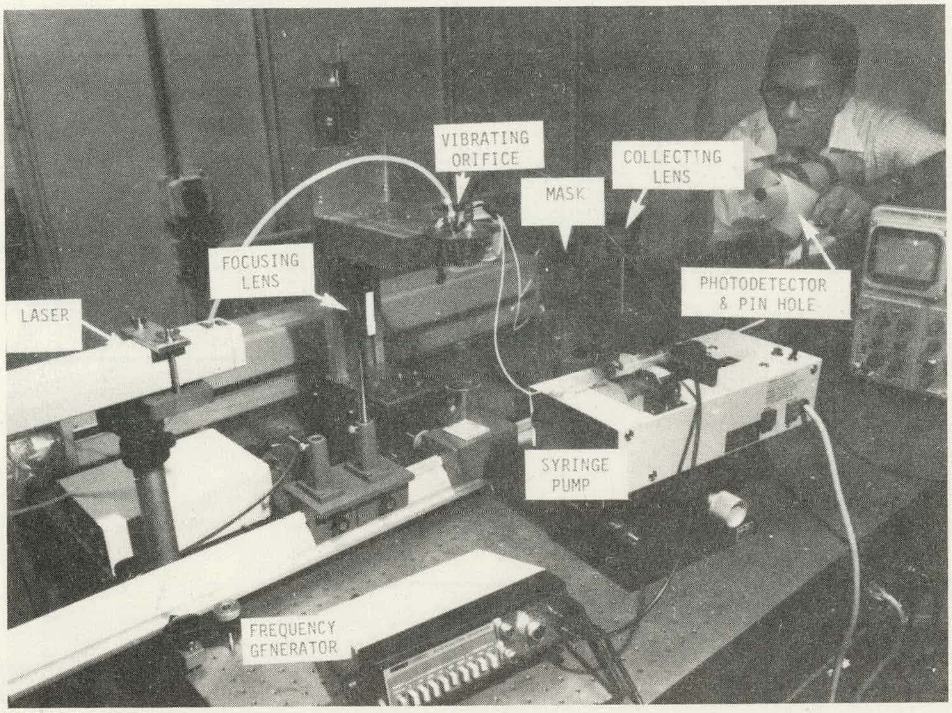


Figure 11. Picture Of The Bench Scale Experiment

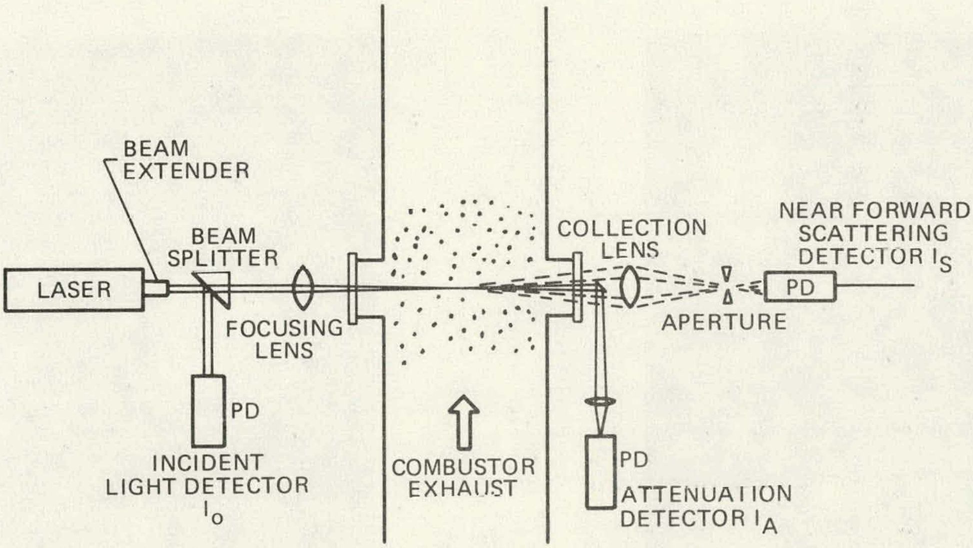


Figure 12. Schematic Of The Experiment Setup

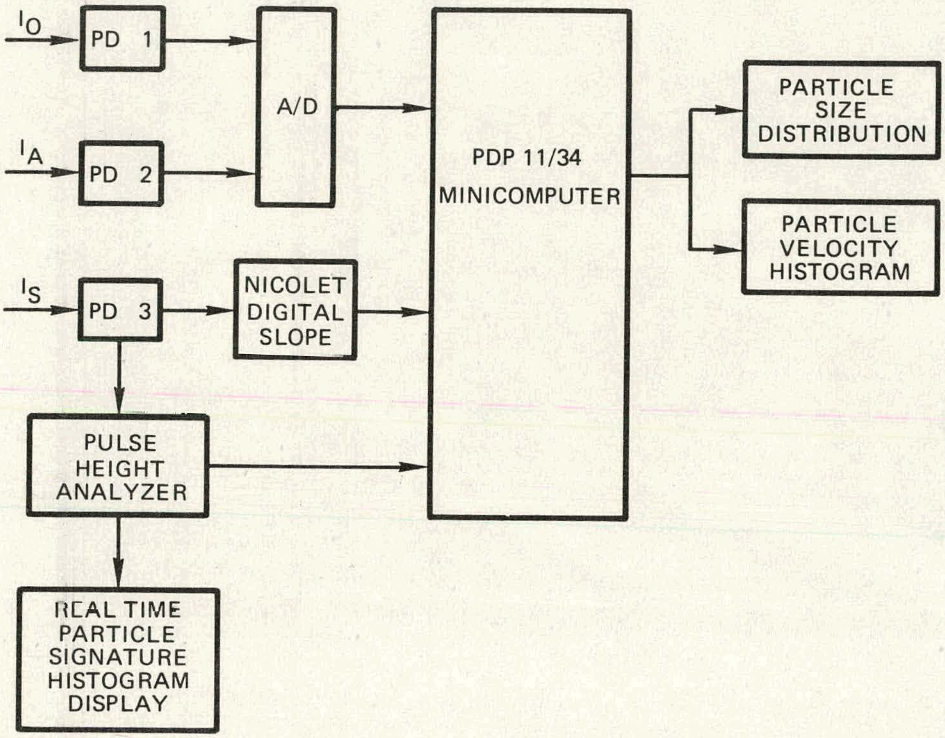
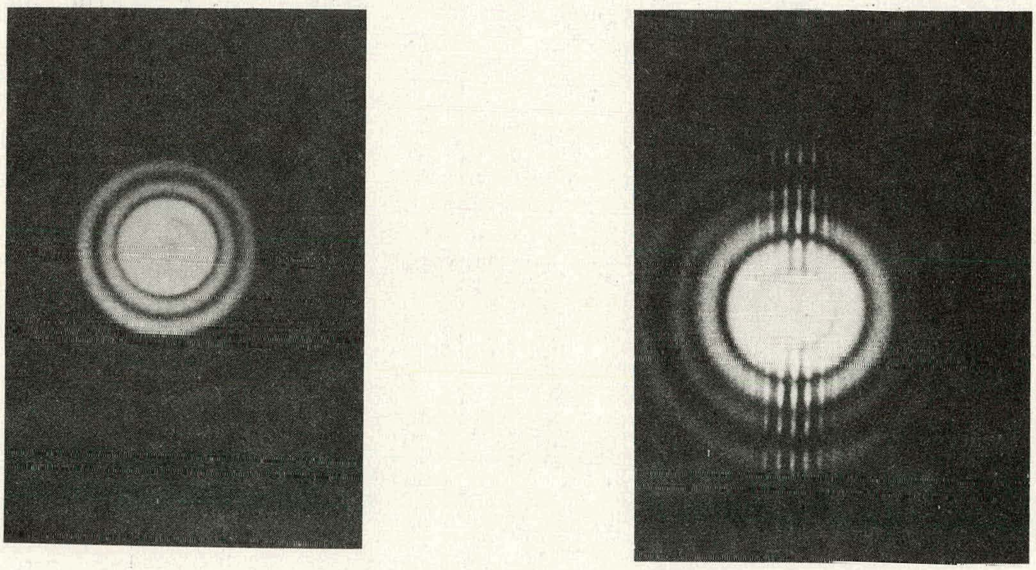


Figure 13. Block Diagram Of SANFS Data Acquisition System



(a) 50 µm

(b) 30 µm

Figure 14. Typical Diffraction Patterns from Monodispersed Alcohol Droplets

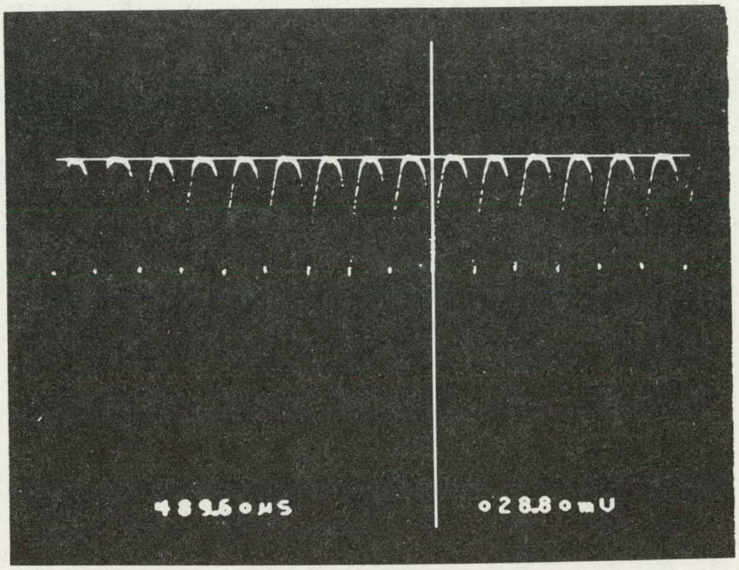


Figure 15. SANFS Signal Output Of Droplets From A Monodispersed Droplet Generator

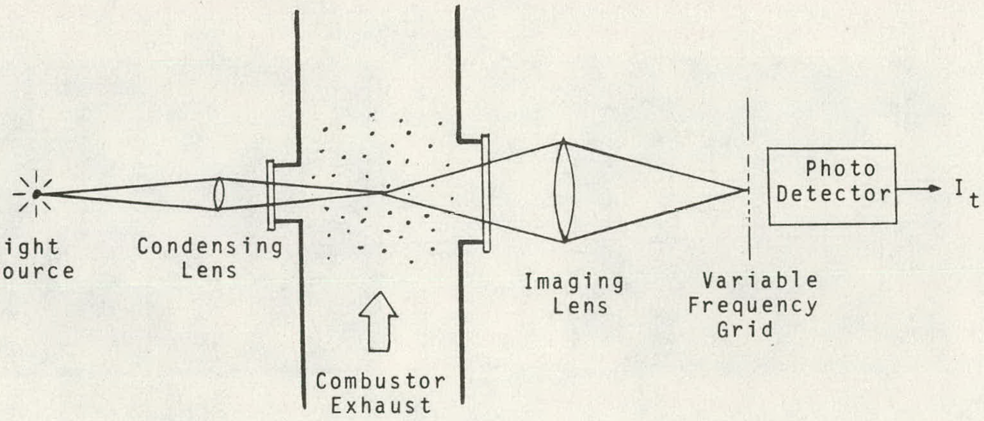
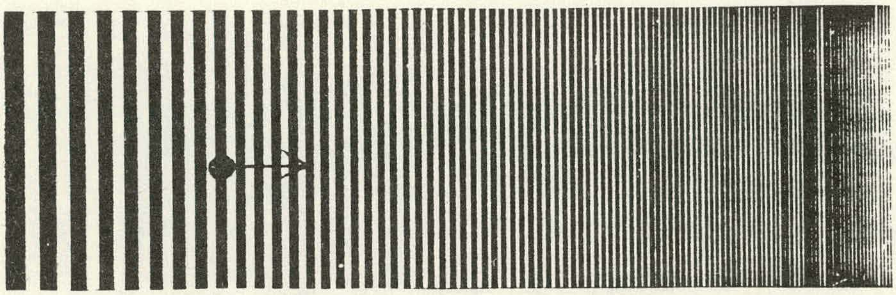
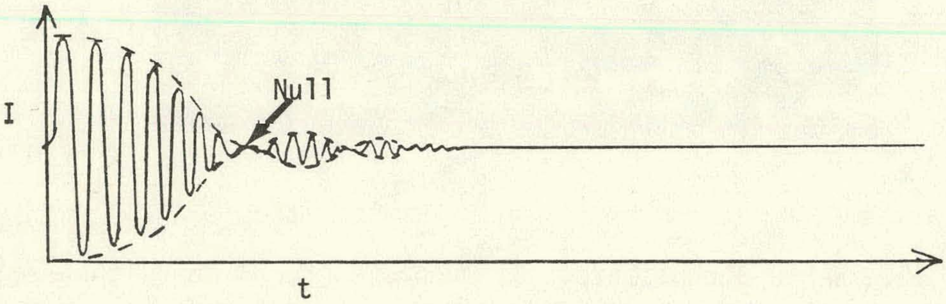


Figure 16. Variable Grid Technique for Particle Sizing

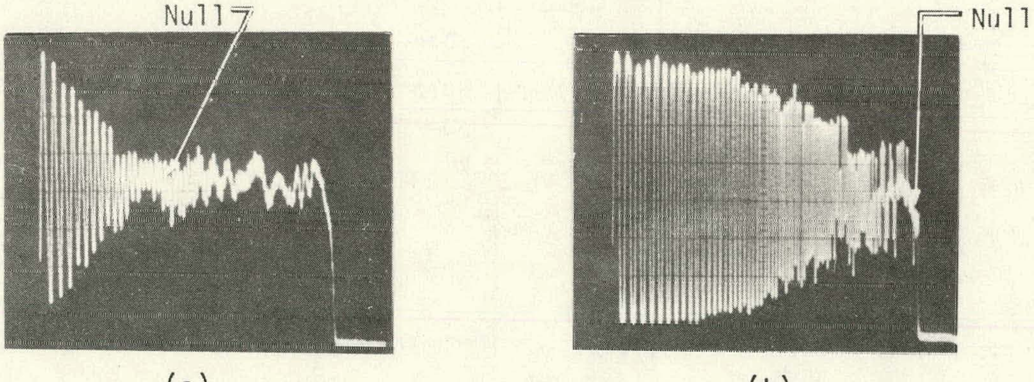


Grid



Detector Output

Figure 17. Log-Frequency Grid and Corresponding Response Curve



(a)

(b)

Figure 18. Signatures Obtained by Scanning Circular Aperture Across the Variable Frequency Grid of Figure 17. (Aperture (a) is three times the diameter of aperture (b)).

Banquet Speech for 1979 Symposium

Dr. George R. Hill

It is a pleasure for me to renew acquaintance with many of you of whom I have had the privilege of working with in one of my previous careers. When Nancy O'Fallon invited me to be your speaker, she indicated that it would be in order to give some background on the instrumentation needs that I see as requirements to solve the nation's energy problems. This brought back a flood of memories from the OCR days and from EPRI experience; so I put together an outline of some of things that I would like to talk about briefly before receiving the program. You don't ever want to do that, because about 2/3 of the items that I recalled as being critical to solving the energy problem, in 1972 in Washington and then in Palo Alto with EPRI, most of you are working on. All the solutions are not in, as you know. We desperately need as intense an effort in developing the instrumentation, the analytical capability, and the control capability for the multitude of processes which we are going to have to develop on a commercial level, as we can develop. Please continue to work as hard as you can; get all the support you can, so you can do the job the proper way. In the presentation tonight, it occurred to me that a classification scheme might be useful in order to bring us up to speed together.

Being back in the academic fold, as I was reviewing my textbooks I was struck by the similarity between the quantum energy levels in atomic orbitals and the development sequence in the energy field. This is a different way to tie things together, but there are a lot of similarities that one can elaborate on. I'll touch on some of them. The first slide is the chemist's quantum energy level picture, not the physicist's kind. You'll have to forgive me for the simplicity of the diagram, but I think it is quite useful. As you recall the energy levels in the elements as we move across the periodic table have in the first two elements an "s" state. In the next elements there are "s" and a "p" energy levels, and so forth. Let me say a word more about this basic diagram itself, so you can see some of the similes that can be drawn as you move from one time period to another. In the initial time period, prehistoric, with two "s" subenergy levels, all the work was done by man or animals. I figure if you were affluent you had a +1/2 animal working for you; if you weren't you had your wife or family do the work and you were a -1/2, but it was still physical labor by individuals, if you please. In the next era, in the "p" level, mechanical inventions developed which made possible improvements in transportation, and allowed for manufacture, and for energy production. These multiplied the capability for doing work and raised the standard of living. While the cost coordinate increased life was made a great deal more pleasant.

As we move to the "d" energy level in the 3rd Era, you still had human and animal power, but at a still higher cost. The "s" level in the third time period was more expensive than the "p" level in the preceding time period. There are some subtleties here that are a lot of fun to play with; I shan't dwell on them too long, however. But it occurred to me that as mechanical inventions were put to use in the development of the 5 "d" levels of natural energy resources. These include natural gas, liquefied petroleum gas, petroleum, coal, and then a derived form, electricity. As we move to the present time we increase the options again. In the 7th level "f" state we move into an era where synthetic liquids are not only a possibility, but a real necessity. It turns out that there are seven of these options that are available to us that are different enough to list separately: (1) methanol production from coal, (2) Fisher Tropsch gasoline, (3) Solvent Refined Coal, (4) Exxon Donor Solvent, (5) H-Coal, (all somewhat different methods of generating fuel for our mobile system out of coal) and then the (6) Consolidation Coal (CDF) process and, finally, (7) a multi-product process where you produce char, gas and liquid, as exemplified by the Coal Con and the

FMC COED processes. Now for some of the subleties. If we could go back to the first slide, you'd recall that the energy level difference, or the cost level difference, is very small. It's hard to say for sure which of those process routes is going to be the most economic. Those of you in DOE are being asked by the Congress to make such decisions. I feel for you, because it's not possible. The differences in cost just aren't defined until we get commercial plants on line and have some experience with them. And we won't get those plants on line and have them successful unless the work that you're engaged in is successful. I really feel this keenly. Another analogy: the "f" states in the periodic table are represented by the rare earth metals. Those of you who recall your freshman chemistry will remember that these elements were lumped together in one box in the early periodic table. Early on there wasn't sophisticated enough instrumentation and analytical techniques to separate them and identify them. This separation required the development of the nuclear era with the instrumentation that many of you have been involved in. The same kinds of instrumentation and equipment development are going to be required for taking advantage of the present day options in the synthetic liquid and gas developments.

In the early "d" quantum level period when coal of one rank and grade from one particular mine was burned in a boiler specifically designed around the coal's specifications, coal analyses requiring 1 to 3 days to complete were acceptable. With our present "f" quantum technology, the reliable operation of coal conversion systems sensitive to small variations in sulfur, in mineral matter, in trace elements, even in moisture, make such long time delays intolerable. To shorten the time for analysis we initiated one project in the Fossil Fuel Department of the Electric Power Research Institute that has as its goal the development of a single, multi-sensor instrument for continuous monitoring (with instantaneous readout) of the sulfur, water, mineral matter, and heavy metal atom content of a continuous stream of coal on a conveyor belt feeding a liquefaction reactor. After writing that beautiful long statement, you can realize how delighted I was to learn from the program that O. J. Tassicker is reporting in this symposium about the now developed instrument. Many of you had a part in it's success. The thing that the EPRI project did was to bring together the techniques that have been developed in the nuclear area really - neutron activation - with the type of people that make materials transporting equipment. An education symposium was held where these two groups were brought together - some of you probably were there giving input - and a mutual education process occurred. I think we're going to end up with an instrument that will make possible instantaneous control of the coal feed, not only in the power plants, but in synthetic fuels plants as well. The instrument is very valuable, because you cannot any longer wait a day and a half or two days for the results of an analysis while the coal is going into the reactor at a rate of a thousand tons a day.

One of the trips that I was able to make during the year and a half I served as Director of the Office of Coal Research was to the newly constructed combined-cycle power plant at Leunen, West Germany. That power plant was designed to couple together a Lurgi gasifier with an expansion turbine and then finally a power turbine. This coupling would increase the efficiency of the system and generate electricity environmentally more suitably than when you burn the coal directly - an admirable goal and one that looked like it would be easy to solve. The advantages in air pollution control and the increased efficiency of converting coal to a clean gaseous fuel were initially unsuccessful. It was 5 years, at least, before they worked the bugs out. The first reason was that no control equipment had been developed to interface between the Lurgi gasifier and the gas turbine. That was Problem #1. And, second - this is a revelation to me - they found that the combustion gasifier chemical engineers used a completely different set of terms and units to describe the components of their gasifier from the set familiar to the electrical and mechanical engineers at the power plant. It was as if they spoke different languages. It was a fantastic thing. Five years of hard work was required before the equipment was developed and that relatively simple plant operated satisfactorily. Profiting from their experience the U. S. electric utility industry decided to initiate a combined-cycle pilot plant effort. They chose the Con Ed system. The Powerton plant was to be the site for a Lurgi gasifier to be coupled, not to an expansion turbine, but to a combustion turbine, one step further than the Germans had gone, coupling it finally into a boiler. It turned out that the cost increases over the initial estimate (due to the need for unanticipated fuel gas purification equipment, and due to the development requirements for interacting control equipment) caused the demise of that Powerton project after several years of effort. Luckily for EPRI, the cancellation occurred before the gasifier turbines were purchased; the investment was not really all that heavy in hardware. Part of the problem here was that the success in the space program, the lunar landing program in particular, with all its beautiful, automated, computer-controlled redundancy misled the developers of more prosaic processes for generating electricity from synthetic fuel into the mistaken notion that the development of interacting control and analysis equipment was easy and would keep pace with the development of the major hardware components subject to high stress conditions. More power plants have been shut down due to the failure of valves and pumps and filters than due to failure of the large scale components. For the want of a nail - I think all of you remember that little statement - for the want of a nail, a shoe was lost; for the want of a shoe, the horse was lost; for the want of the horse, the rider was lost; for the want of the rider, the message was lost; for the want of the message, the battle was lost; for the want of the battle, the war was lost.

Well, that statement - for the want of a nail - might well be inscribed on the walls of the industry decision-makers who allocate funds for energy research and development.

Early in my work at the Office of Coal Research I felt that the effort in instrumentation and control equipment was not great enough. We set about to try to develop the equipment to eliminate potential bottlenecks. I read in a recent DOE report, that 5 companies have finally been funded to do work on high temperature gas cleanup. We, I thought, had that started some years ago.

The effort of the Reliability and Performance program area for which I had responsibility at EPRI was expanded fivefold during my last six months at EPRI in order to be able to concentrate sufficiently on the development of equipment which can improve the percentage time on line at new and existing power plants. An economic analysis demonstrated that a 5% improvement in power plant reliablity nationwide can save ratepayers billions of dollars in the construction of new plants.

Let me touch briefly on a few of the other program areas that have interested me over the years. I'm pleased - very happy - to see that many of them you are working on, judging by the titles of the papers in this symposium. For example, there needs to be instrumentation developed in the coal oil slurry area. As we try to reduce the quantity of oil we're consuming, one way we can do it is to burn, in power plants that have the capability of handling some coal, a slurry mixture of coal and oil. This will require some new kinds of equipment for forming and stabilizing coal oil slurries and for injecting through burners (without phase separation) that two phase system. There needs to be some work concentrated here. Another major area that I again have anxiety about, having recently visited a power plant in the central part of Utah, is the disposition of the solid waste from the SO_2 absorber system. A political decision was made that power plants located in remote areas burning coal with less than 0.6% sulfur must have a flue gas desulfurization unit put on, even though that same coal could be burned in New Jersey without a control device and meet all the EPA requirements. I fail to understand the logic behind that.

I think those of you who are working with models will appreciate another related development. UP&L built the first 500 MW unit of the plant without a flue gas desulfurization unit. Construction was underway before the EPA regulations were established. The sulfur dioxide dispersion model that EPA used predicted that the first plant was going to cause fumigations in the hills surrounding and in the town down the canyon from where the plant was located. This would therefore require flue gas desulfurization. Due to the predicted SO_2 problem, EPA required the company to agree to put on a flue gas desulfurization unit in the second unit they built. The first 500 MW unit operated a year, during which time SO_2 was monitored continuously. Not once did they find a detectable quantity of SO_2 at any of the locations that the model said would give 0.1 ppm fumigation. UP&L approached the state EPA for permission not to put this expensive unit on the second plant. They were given permission. However, EPA Washington sent a telegram saying, "As you were. The model predicts fumigation, therefore you will build the second unit with the SO_2 absorber in it." I had believed that you build a model based on data; you test it; get additional data; then change the model if it doesn't predict correctly. You don't say the model is right and the data are wrong. This is the position that the EPA took in this particular instance. One consequence of this decision is the production of a waste product that comes out of the reactor as a slime which defies description. You can't retain it even in a clay-lined pit. The aqueous phase leaks into the ground water in the vicinity. The maintenance and operation of that particular system involves more people than are required to run all the rest of the plant. There may be some logic here, but I fail to comprehend it. We do need better instrumentation and better knowledge of how to handle these waste products if we're going to be successful. There is technology that is being developed, which must be improved, in the utilization of garbage in power generation. The separation of the aluminum, the iron, the glass, and the handling of the plastic, so you don't generate more noxious fumes than are allowed, requires a great deal of effort. I think some good work is going on here.

One of the developments in the flue gas scrubber technology is the need for a better mist eliminator. Some of the units produce a mist that goes out the stack and settles around the plant. This is worse than the original SO_2 was, and has to be eliminated.

We found out in some of our oil shale work at the University of Utah that during shale pyrolysis you generate an aerosol - little tiny droplets that defy collection. They'll go through any condenser system we had available. We tried using a filter of glass wool. But this glass wool stuff comes smoking out the filter just like nothing was in the way. I think an electrostatic device coupled with some kind of filter may solve the problem. Hopefully, somebody may be working on it. I find I'm out of date on a lot of these things, so you can tell me before I leave tonight, "Hey, we have that one licked; we have developed this device which solves the problem."

One of the interesting developments that O. J. Tassicker, who is one of your authors, was heavily involved in at EPRI was the development of the high intensity ionizer to increase the efficiency of electrostatic precipitators. I hope I don't offend any of you who are close to the utility industry or the electrostatic precipitator manufacturers when I report that all of the research that might have been done to improve the efficiency of particulate removal had not been done. The claims for 99.9% removal efficiency were rarely achieved. It has now been possible to improve the efficiency of an electrostatic precipitator by about 50% by preionizing the particulates by passing the stack gases through a little sandwich plate between the stack and the electrostatic precipitator.

By putting a high intensity field on you charge up the particles so that they migrate more efficiently to the charged electrodes in the electrostatic precipitator.

Another particulate problem is that there needs to be improved fine particle (0.1 to 1 micron) analyzers and removal systems. Many of you may have been involved in the development of some of the initial equipment. A piece of equipment has now been developed which I think can be used routinely. Earlier devices required a Ph.D. to make successful measurements. Industry will appreciate this, believe me. One of the problems in the electric utility industry was historically that none of them had a staff chemical engineer. When a utility was asked to put in such chemical plants as flue gas desulfurization plants, they had problems. Somebody figured that if you hybridize an electrical and a mechanical engineer, you can come up with a chemical engineer. This assumption proved to be wrong in a very expensive way.

Fabric filters are part of the set that is going to be worked on in high temperature gas cleanup systems. Bag house filters remove the fine particles, the ones you inspirate, that get stuck in your lungs and can cause lung problems. But much development work still needs to be done on their durability.

Another problem is NO and NO_2 analysis, reduction, and control. The EPA regulations have outrun the technology fairly severely here. We need to determine the mechanism of NOX reduction in a fluidized bed. The level of emission is below what you'd predict it would be. We don't know if it's a chemical reaction with carbon monoxide, or whether it's a surface catalyzed reduction with carbon. Even so, we still have to reduce it further. I just hope we don't get to the point where we require the Japanese solution, which is to inject ammonia in the stack to react with the oxides of nitrogen. I made a calculation when that suggestion was made in a meeting at EPRI in Palo Alto one day. The calculation showed that we're not manufacturing enough ammonia in the whole United States to reduce the NOX in the power plants planned for construction in the next 10 years. And besides that, nobody had at that time successfully shown that you can get complete reaction of the NH_3 and NOX in a coal fired combustion system. All the data aren't in here yet.

In solvent refined coal production, we're still faced with serious problems on solids/liquids separation. We also have problems in combustion burner development. B&W and Combustion Engineering both have developed burners for SRC combustion that finally work satisfactorily, but there's still a lot of room for improvement here. Staged combustion will reduce the NOX; there are some innovative ideas in equipment design that really need to be developed to keep the NOX low in a more natural way, rather than requiring chemical process to reduce the concentration.

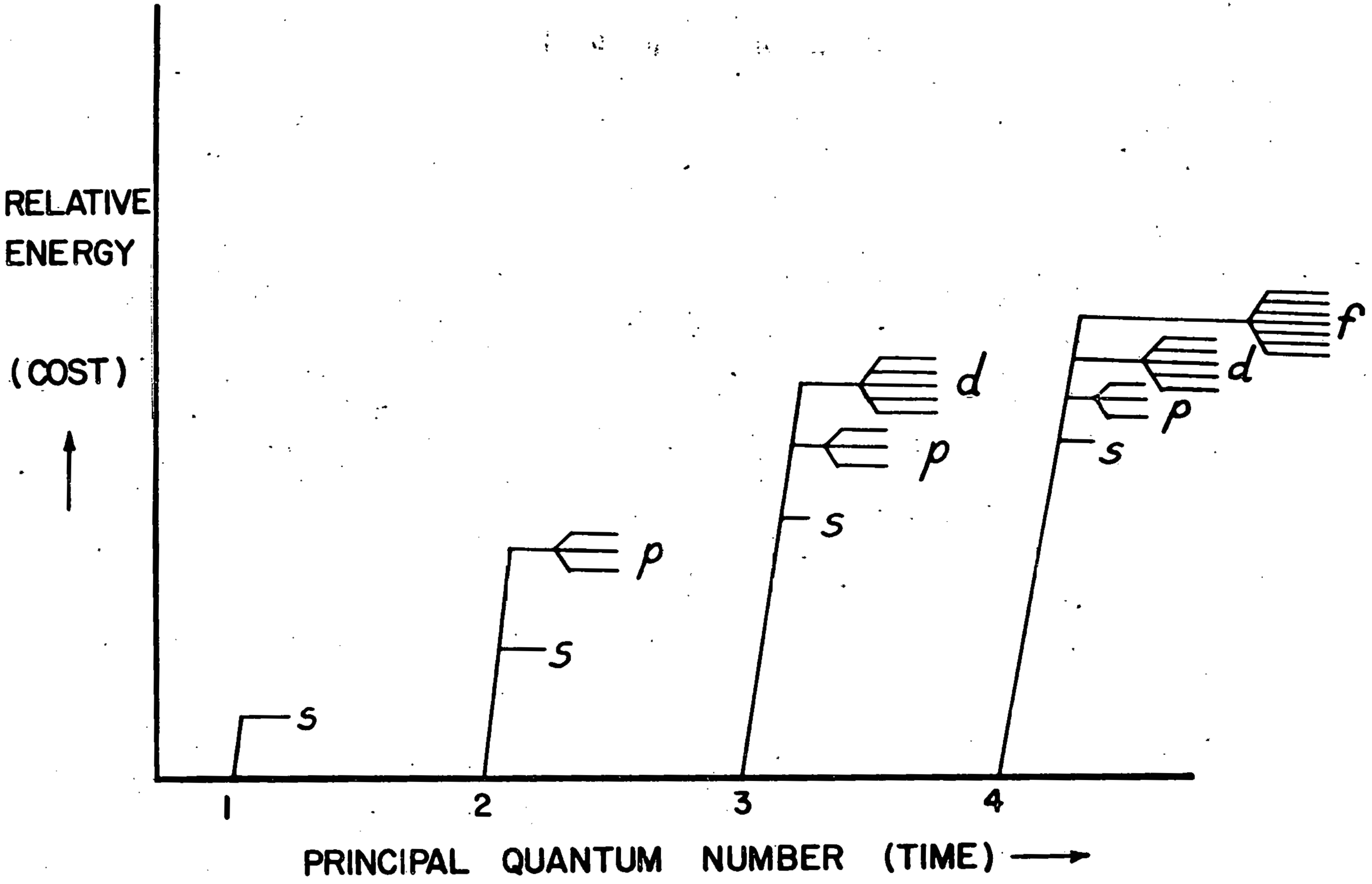
Another interesting area is in the substitution of low Btu gas for natural gas in power plants. Combustion Engineering and B&W and one of the national laboratories calculated the efficiency of combustion of gases of different heating values. We had a symposium at Carmel to discuss the results. Calculations had shown that the flame temperature of a mixture of hydrogen and carbon monoxide with a heating value of only 300 Btu per cubic foot was within about 50° of the flame temperature of methane air mixture. The reason, of course, is that in the methane air mixture you bring in so much nitrogen that the total volume of gas heated is very great compared to the volume requirement for the CO/H mixture. The contractor, B&W, plotted the calculated flame temperature that could be achieved as heating value as you went from pure methane clear across in heating value to a low Btu gas. The calculations showed that a gas of heat content 300 Btu's gave 110% as much energy as you got burning methane. The efficiency dropped off quite rapidly at lower heating value because then you were putting in such a large volume of gas. It became very evident that we could substitute 300 Btu gas for natural gas and come out ahead with minimal piping changes. The possibility of going the intermediate Btu gas route for industrial and power production purposes, with a great savings, would save large quantities of natural gas. Some of these concepts have practical and very economic ramifications. Let me touch briefly on a few more and then I'll let you go. This is a delightful place to be - Denver - and hearing talks this time of night is a terrible ordeal. You had a good dinner, I think, and can stand to be punished a bit; then I'll finish.

We haven't yet developed a good diesel engine smoke depressant. Since we're going to have to have more automobile diesel engines, this problem will need a solution. I don't know how the diesel engine manufacturers have gotten by so long without EPA restrictions.

The next one - combined wet/dry cooling towers for power plants. In the western part of the country we're short of water. That means that ultimately we are going to have to go to either dry cooling towers or a wet/dry cooling tower to minimize the quantity of water that is required. Just before I left EPRI, we were talking about using ammonia as a heat exchange fluid in such systems. Somebody had made a calculation that if you used ammonia as your coolant, pumped it over, and then used water to absorb the heat as you compressed the ammonia again, that you could reduce the power requirement for the blower sufficiently to cut the cost by half. It should be evident by now that with the very sophisticated equipment and instrumentation knowledge now available that technological improvements in plant operations will be made that can make a real difference in the cost processes and products. One major problem we've got to deal with is how to remove the very fine particles from a combustion smoke. If you plot a particle size distribution curve in a smoke stream coming out of a power plant, you find a fairly normal distribution curve. However, it has a spike in it at about, as I recall, 0.08 microns. There is a tremendous concentration of these little, tiny, spherical beads. These particular particles evidently are condensation particles enriched in heavy metals. Unfortunately, that size particle is inspirated and adsorbs in your lungs. I don't know how you build a device that selectively filters out the large number of that size particle, but I'm sure it will be done.

Finally, in the shale oil and coal liquefaction products we're finding that instead of getting a nice, petroleum-like liquid, you're awfully lucky if 50% are hydrocarbons. The others are heterocyclic oxygen, nitrogen, sulfur containing multi-ring components. As you heat these molecules they don't split nicely to give you a lot of high octane, benzene type molecules. Rather, they break single rings and then degrade - one ring at a time. And so if you start with a big platelet with maybe 20 benzene ring aggregate, all you can get out of that with present technology is one benzene or toluene and you produce the rest as gas. So, some of you who are good at enzyme chemistry might develop a dual functional catalyst that will allow these big platelets to sit down on their surface to be cleaved. Scissoring the molecule right up the middle, instead of peripherally degrading it will double the high octane liquid production. Gasoline cheaper than we had it before the most recent price increase could be the result.

I hope you'll realize I'm one step away from what you're really doing. I have described some of the problems which have needed attention in my work. Some of them you are solving I see from your reports. I commend you, I encourage you. your success is imperative if we are to move forward successfully. We wish you success in your work. Thank you very much.


RELATIVE ENERGY
(COST)
s
s
p
s
p
d
s
p
d
f
1
2
3
4
PRINCIPAL QUANTUM NUMBER (TIME)

ENERGY QUANTUM RELATIONS

STATE DESCRIPTION	EXAMPLE
PRIMITIVE s	HUMAN POWER – ANIMAL POWER
MECHANICAL INVENTION p	TRANSPORTATION MANUFACTURE ENERGY PRODUCTION
NATURAL ENERGY RESOURCES d	NATURAL GAS LIQUIFIED PETROLEUM GAS PETROLEUM COAL ELECTRICITY

SYNTHETIC LIQUIDS

f

- CH_3OH
- FISHER TROPSCH GASOLINE
- SOLVENT REFINED COAL
- EXXON DONOR SOLVENT
- H - COAL
- CONSOLIDATION COAL (CDF)
- MULTIPRODUCT - COAL CON
- FMC - COED

ONLINE CORRELATION FLOWMETERING IN COAL CONVERSION PLANTS

K. G. Porges, F. R. Lenkszus, R. W. Doering, W. W. Managan,
C. L. Herzenberg, C. A. Nelson, and N. M. O'Fallon

The first application of correlation to the measurement of flow speed goes back some 30 years,[1] during which the method has developed considerably but still remains a technique suitable only for laboratory and special applications, requiring at best some occasional attention by a specially skilled operator. To be acceptable in an industrial plant, a flowmeter must read out entirely autonomously over the specified range (from startup to full flow) of the measurement site. Since the function desired is usually the feedrate, a measurement of the flow speed by correlation is only one ingredient of the readout, and an additional online determination of density or composition is also needed when the flowing medium is inhomogeneous. All this calls for a dedicated computer, which is required to determine the mean flowspeed or component transport rate by correlation (with or without help from special circuitry) and to incorporate enough intelligence to track and search for the correlation as the flow changes; in addition, the computer must evaluate the density/composition from another set of measurements, and finally, the feedrate readout is to be computed at acceptable intervals from the density and velocity data.

Until quite recently, a computer capable of accomplishing all these tasks in the available time would have been prohibitively expensive. Since the advent of 16-bit microcomputers, the practical implementation of the necessary basic program by means of relatively cheap LSI chips and boards would appear to be no longer unrealistic, and this perhaps makes a review of correlation flowmetering of somewhat more than academic interest in connection with coal conversion, where such flowmeters can offer certain specific advantages.

In flowmetering, as in other measurements, the amount of information which is available for processing increases with the number of sensors; a corollary of this generalization is that parameters which a single sensing head must grasp through direct exposure can be inferred from the perceptions of several sensors viewing the process from a safe distance. Correlation flowmeters, which operate with two sensors, are thus inherently non-invasive. If more sensors are deployed, then sometimes more information results; for multi-phase flow, this principle can be made use of to determine separate feedrates, as will be discussed, all without sampling the medium or obstructing the flow. Since measurement sites in coal processing plants often feature high temperatures and pressures, while the flowing medium is abrasive and tends to clog even when no obstructions are inserted, the instrumentation of pilot, demo, and full-scale coal conversion plants evidently offers some scope to correlation schemes.

It is not our intention to claim that correlation flowmetering is the only (or even necessarily the most cost effective) technique for every measurement site. Other non-invasive flowmeters have been available, and some of these may be found suitable for coal conversion plants. It is well, however, to keep in mind that velocity measurement is only one of several tasks which together provide the desired readout; it also should not be overlooked that on-site calibration, required whenever the flowmeter signal varies with environmental conditions (e.g., the temperature), can be very difficult.

To provide a perspective for correlation flow velocity measurement, it may be useful to connect that two-station scheme with other, readily understandable two station schemes. Aside from Doppler frequency shift measurements, which in fact will be considered in another report at this meeting,[2] these schemes are all based on "tagging": injection of salt, dyes or radioactive tracers in a pulse or steady stream has long been exploited for flow measurements in gas and liquid phase flow.[3-5] Accuracies of 0.2% can be achieved[5], hence this general method can be useful for intercalibration purposes, as it has been in studying flow.[6-8] Measurements are, moreover, absolute: when certain procedures and computation methods are used, tagging effects a fair (unbiased) sampling, independent of the flow pattern.

The scope of tagging is broadened and its most objectional feature, the injection valve, eliminated if the medium happens to contain a nuclear species which can be activated through the duct by neutron irradiation (other means of inducing nuclear transformation lack penetration or require prohibitively cumbersome equipment). The signal delivered by a downstream detector can again be processed in such a way as to make the velocity reading absolute[9,10] if the neutron irradiation is pulsed. For gas streams, a similar scheme has been described in which a local beta or gamma source produces ionization, the latter being detected downstream by applying a collection protential to a plate which can be flush with the duct wall.[11] Yet another decaying tag scheme, NMR flowmetering,[12] is applicable to conducting liquids, but might work for a slurry.

Returning now to Pulsed Neutron Activation (PNA), which of all described through-the-duct tagging schemes has the best overall potential for application to ducts of arbitrary diameter, carrying multi-phase media, it is sometimes found that available pulsed neutron sources cannot produce a measurement with adequate precision and also within an acceptable time span. In TOF neutron spectroscopy, where a similar source intensity problem is often met, it has been found possible to increase the mean pulsing rate while at the same time randomizing intervals between pulses, with the net effect that correlation processing of the detector count rate allows one to infer the desired information with considerably enchanced statistical precision, speed, or both.[13] Supposing now, for the moment, that this stratagem will work for PNA (tests of this possibility are being planned at our laboratory), then this scheme in effect bridges the gap between tagging and correlation processing, as illustrated schematically in Fig. 1: instead of the upstream tagging source, an upstream detector is deployed to sense the passage of <u>natural</u> inhomogeneities in the medium, also occurring in random sequence. The similarity is more than superficial: in both cases, the statistical precision of a measurement obtained within a given acquisition time varies with the ratio of tag intensity (or natural fluctuation intensity) to channel input noise; moreover in both cases the downstream signal is degraded by turbulent dispersion of the tag or natural inhomogeneity en route to the detector site. The latter effect can sometimes be dealt with through optimized detector siting, and has also been reduced by processing in the frequency regime, as yet too complex to be applied online, which will be briefly considered below.

Natural inhomogeneities which can be harnessed for correlation velocity measurement include local fluctuations in temperature, vorticity, density and composition; the first two of these are specific for homogeneous media. Temperature can be sensed only by passive means which, however, can be made extremely resistant to a hostile environment. Passive sensing results in a somewhat poor S/N ratio, necessitating long acquisition times;[14] the availability of radiation resistant thermocouples has led to the application of this scheme in flow measurements within the core of nuclear reactors.[15] Vorticity has been exploited in a clamp-on flowmeter which detects the phase shift induced in a sonic signal by the radial velocity components of local vortices.[16] This is

an example of an active sensing scheme in which the medium is "interrogated" by some some means, resulting in an enhanced S/N ratio. Other active sensing schemes which address inhomogeneities in density or composition are summarized in Table I; all these methods also lend themselves, in principle, to the determination of mean medium density and/or composition and are thus of specific interest for the type of flowmeter this review emphasizes. Each of the schemes listed works best within a certain range of geometry and flowing medium parameters; fortunately, different techniques tend to complement each other, with some overlap. Sonic beam transmission has been much used with direct timing rather than correlation processing,[17] which can dispense with inhomogeneities and is therefore more applicable to homogeneous media than to slurries (clamp-on commercial versions of this kind of instrument, which measures flow speed only, are available from several commercial vendors). Electromagnetic radiation transmission, long used for high-precision densitometry,[18-20] has been shown to yield correlation velocity measurements for light[21] and gamma radiation;[22,23] optical correlation velocity measurement is best applied to gas-solids streams with less than 10% solid while gamma transmission offers the best scope in dense streams (liquid/solid, gas/solid) and ducts of larger diameters. Another type of sensor detects the response of the medium to an impressed EM field, which is conveniently possible by surrounding the duct with a capacitor. This widely practiced correlation scheme[24-26] senses changes induced in the mean dielectric constant of the medium within the capacitor, resulting from the presence of solids. Given a paramagnetic medium component, the same game can be played with the magnetic susceptibility; lastly, fluctuations in medium conductivity[27] have been used for velocity measurement.

This list of sensing possibilities, not necessarily exhaustive, sugggests that there is a reasonably good chance of finding something which works in a large and various number of specific measurement sites. We now pass on to the next topic: how is it done?

The correlation process starts with fluctuating signals from the two sensors, which must be digitized to allow the digital computer to work. This in turn involves sampling, at a rate which preserves the information content of the analog signal. As correlation processing usually requires a large number of samples, another consideration is the readout delay $N\tau$ where N = number of samples and τ = sampling interval = 1/sampling rate. Now let L = length of the duct region scanned by each individual sensor and ℓ = length of a typical inhomogeneity, e.g., a cluster of particles, then we can define the dwell time $t_d \doteq \bar{v}/((L+\ell)$ and it becomes evident that for a choice $\tau >> t_d$, information is indeed lost, whereas the choice $\tau >> t_d$ samples too frequently: not much additional information is gained whereas more input noise is admitted through the concomitant increase in bandwidth. Thus, an estimate of the mean flow speed $\bar{v}$ allows a good choice of the sampling rate; in practice this estimate would have to be made on the basis of the maximum flow speed. In typical coal processing plant sites, a 1-kHz sampling rate covers the situation adequately; this results in a readout delay (and thus approximate readout refresh interval) of the order of 1 second for N = 1000.

Before, or after, digitization, it is expedient to subtract the average of each fluctuating DC signal, given that fluctuations may amount to only a small fraction (typically less than 1%) of the mean signal; this allows the computer to work with small numbers. The resulting set of bipolar samples might look somewhat like Fig. 2, which was obtained in a test on the HYGAS plant slurry feedline with capacitive sensing. A strong similarity in the two records is readily noticed and one can thus estimate the transit time between sensors by eye, displacing one record with respect to the other until the best congruence in obtained. In other situations, to be sure, matching by eye is more difficult as noise masks the correlated component. This calls for a computer program which can elicit the desired information from fairly noisy records, and moreover do this very rapidly, with some judgment. When faced with this kind of requirement, it often helps to present the available information graphically and then study the plot for clues; we shall do so here, plotting upstream samples against downstream samples, as shown in Fig. 3. Each point on this plot represents a pair of concurrent (simultaneous) samples and the fairly isoazimuthal distribution indicates that there is no noticeable correlation (which would order the points along a line with positive slope, passing through the origin). Repeating this plot, aptly known as a "scatter diagram", with an offset of 20 samples (such that each point pairs a D-sample with a U-sample taken 20 seconds earlier), grouping begins to appear (Fig. 4). Now increasing the offset or lag by 16, 17, and 30 more sampling intervals, one obtains the three plots shown in Fig. 5. The first two of these show strong grouping, the third weaker grouping, indicating that a delay of 50 sampling intervals has overshot the transit time, while there is no visual distinction between 36- and 37-sample delay.

To choose (in this illustrative example) which delay comes closer to the transit time, we may invoke the well-known Principle of Least Squares, from which we deduce that, given a known straight line

$$X = mY \tag{1}$$

and several sets of points (x_{i+k}, y_i); $i=1,2,3,\ldots N$; $k=0,1,2,\ldots k-1$; the set for which the sum of squares

$$S_k = \sum_{i=1}^{N} [(x_{i+k} - X_{i+k})^2 + (y_i - Y_i)^2] \tag{2}$$

is the smallest is the most strongly correlated. As depicted in Fig. 6, the simultaneous fitting of x and y yields another relation,

$$(x_{i+k} - X_{i+k}) = -m(y_i - Y_i) \tag{3}$$

from which X,Y can be eliminated; thus

$$S_k = \sum_{i=1}^{N} (m^2 x_{i+k}^2 + y_i^2 - 2m x_{i+k} y_i)/(1 + m^2). \tag{4}$$

The first two terms of this expression are essentially independent of k if N>>K; therefore, if S_k is to be a minimum with respect to the choice of k, then the third term must be a maximum. Indeed, a plot of this third term against k for the set of data used in the foregoing, shown in Fig. 7, confirms this.

Without resorting to complex mathematics, we have thus discovered the exact program for the online processor: compute the <u>covariance</u>

$$\mathrm{cov}(x,y)_k = (1/T) \int_0^T x(t+\tau)y(t)\, dt = \sum_{i=1}^{N} x_{i+k} y_i \tag{5}$$

for K offsets or points over the record length N, choosing K large enough to capture the covariance peak (and allow tracking that peak if and when the flow speed changes); thereupon find the location of the peak, k_{max}, and compute $Z_{ud}/k_{max} = v$. This still requires two possible corrections, (a) for velocity dispersion, (b) for components, e.g., fine dust, which do not yield strong correlations and may move at a different speed. A fuller discussion of these effects, which could amount to 5%, is beyond the scope of this survey; we note only that detailed studies which would allow the error to be reduced below 1% largely remain to be done. A useful property of the covariance is its immunity to noise: supposing that random noise samples x'_{i+k}, y'_i are added to the signal samples x_{i+k}, y_i in the above expression, then the computed covariance includes four components

$$\mathrm{cov}(x,y) + \mathrm{cov}(x',y) + \mathrm{cov}(x,y') + \mathrm{cov}(x',y')$$

of which the last three tend to vanish as the number of samples increases. If, on the other hand, a fixed number is added to each sample (as would be the case if the average subtracted from each sample before computation was not quite the exact average of the sample set) then the entire covariance is raised on a pedestal (always positive even when the fixed number is negative). Neither kind of signal contamination affects the location of the covariance peak; to be sure, noise does worsen the statistics and therefore, if present, requires more samples hence a longer acquisition time to obtain results within a specified statistical precision.

Having thus found the program, the fastest and least expensive means of implementing Eq. (3) is next on the agenda. Bearing in mind again that a complete flowmeter requires sensing and computing the medium density or composition as well as the mean flow speed, and that both computations may have to be corrected, an online computer is a necessity unless the medium is strictly homogeneous, single phase and thus allows one to infer the density from the temperature (a stratagem widely used by conventional "flowrate" meters which are in effect flow velocity meters and are often sold with a correction table listing true versus apparent readings for various media). One then has the choice of supplementing the computer with additional circuitry for purposes of rapid computation of the covariance, or specifying a computer which can do this task unaided; finally, a number of "correlator" circuits have been described in the technical literature and could thus be fabricated to produce the covariance computation as a stand-alone subsystem.

Considering the latter option first, it turns out that in order to produce a substantial number of multiplications, say 10^5/second, virtually all dedicated online "correlator" circuits make use of parity correlation, in which the magnitude of sample numbers is discarded and only the sign is kept. The multiplication of two signs admits four possible inputs and two possible outcomes, readily implemented in a logic ENOR circuit, while the storage of samples in single bit format needs nothing more elaborate than a shift register. Certain combinations of shift registers, ENOR logic and output stores are available in LSI-hybrid and used in image enhancement for both military and medical applications of correlation processing. Such circuits allow 100 or more multiplications/microsecond in series-parallel connection, which is more appropriate for enhancing images involving 10^5 points than for flow sampling at 1 kHz, yielding 10^3 lags. The question how much useful information is discarded by retaining only the sign of the signal samples has been argued theoretically[28] and is occasionally investigated experimentally;[29] it is difficult to answer in a straightforward way since much depends on the type of signal and background which is being correlated. A more weighty argument against deploying a semi-autonomous correlator is the difficulty of adding some recognition and tracking features to such a unit, vis a vis the relative ease of providing the capability of making decisions by software. If one accepts that a system lacking such features and thus requiring skilled personnel attention is not suitable for an industrial plant, then he is led to an all-software (or software supported by special hardware) implementation of correlation processing, which has been the basis of our work at ANL. An online correlation, peak location and peak tracking program which can cover a range of 20:1 in flow speed is now being tested with an INTEL 8086 system supplemented by an onboard LSI Multiplier, at a hardware cost of about \$3 K. This prototype system, sampling at 1 kHz, can deliver an updated readout every 2 seconds or so; the next version, making use of LSI circuitry already announced but not yet available, would aim for a faster sampling rate and shorter readout update.

Indulging in speculation about future trends in correlation flowmetering, one may note that offline processing appears to be almost at the point of competing with online processing,and could become more cost-effective eventually. The two strong points of offline processing in the frequency regime are that the sampling process hence choice of sampling rate can be managed without constraint, while additional information, neglected by processing in the time regime, is available from the complex phase,[30,31] as already demonstrated in a flowspeed measurement.[32] Just as the practical implementation of our present scheme has had to wait several years for delivery of the first 16 bit micro LSI chips, a complex FFT scheme might begin to look practical when a complex FFT over, say, 1-2k mesh points can be executed in less than 10 ms with relatively inexpensive and readily programmable circuitry, and then would still have to wait until that circuitry is really available.

Before leaving the subject of online processing, a footnote may be added concerning flow/no-flow indicators, for which there appears to be a certain demand in industry. Such indicators can be implemented with almost any sensing device and a few hundred dollars' worth of electronics; in particular, single-chip microcomputers such as INTEL's 8748 (\$70) can apply a simple statistical test to incoming data and determine if and when the flow has stopped.[33,34] Earlier and more costly analog versions of this kind of processor also exist. It goes without saying that the flowmeters described in the foregoing can deliver a no-flow warning as part of their repertoire; if and when only flow/no-flow indication is required, then the saving in detector hardware can be matched by a saving in processing electronics. By way of illustration, Fig. 8 shows the result of thus processing the readout of a clamp-on gamma transmission channel, for 5% solid/gas flow through a 3" duct.

As a final topic, we shall now briefly review the difficult subject of online density or solid fraction measurement. In conjunction with flow velocity, it is evidently necessary here to effect both measurements within the same duct, in close proximity. Gamma transmission has long been a standard scheme for density reading, but close scrutiny reveals that this stratagem is difficult to apply in certain cases. Thus, a small duct diameter with dilute solid/gas flow, or the poor contrast offered by a coal/oil slurry, tend to defeat gamma transmission unless specially shaped duct sections and low-energy radiation, requiring transmission windows, are resorted to, at considerable cost. Fortunately, dilute solid/gas flow is readily sensed with optical equipment, allowing a direct measurement of solids flowrate at extreme dilution (less than 5% solids) or a combined correlation velocity/ density measurement for denser media. Capacitive sensing overlaps the region of applicability of optical transmission and also works well in slurries, where the solid component provides a strong contrast in dielectric constant; an alternative is a Xray transmission and/or sonic transmission measurement. In practice, coal slurries tend to carry a certain amount of gas, which defeats capacity sensing or single beam transmission but can be accounted for by deploying two beams featuring different attenuation.[35] In other cases, the simplicity and ruggedness of capacitor sensing makes that method preferable, and a certain amount of work has been done to cure some of the other drawbacks inherent in that scheme, such as readout sensitivity to the orientation and detailed shape of the EM field across the duct. Azimuthal sensitivity, e.g., due to gravitational layering in horizontal ducts, can be effectively dealt with by field rotation, as described in another paper at this Symposium;[36] radial inhomogeneity in the medium must be corrected for on the basis of test loop calibration measurements. Strong radial clustering of solids in gas or liquid streams has been demonstrated.[37,38] If the possibility of varying amounts of moisture in the medium exists, capacity sensing becomes even more difficult and may well be abandoned in favor of some other scheme which is insensitive to molecular effects, such as sonic/EM beam transmission.

It remains only to dwell briefly on the question of accuracy. Conventional wisdom in the instrumentation field places considerable emphasis on "linearizing" the readout of a channel whose response is in fact non-linear. The availability of an online computer makes linearization a meaningless concept, since any algebraic expression can be programmed to deliver a readout accurately related to a measurement or set of measurements. To implement this, such an algebraic expression must, of course, be available and that is not necessarily the case for some sensing schemes which are otherwise useful. In the absence of a usable expression, test loop measurements can still provide sets of data points which permit exploitation by a number of numerical methods such as polynomial series fitting. Since much of this kind of work remains to be done, the potential accuracy of specific types of density/ composition sensing schemes is difficult to assay and intercompare; this is also true of the accuracy of the correlation transit time measurement contribution to the readout of the flowmetering scheme surveyed in this report.

To sum up, correlation velocity computation and concurrent density computation from the signals of several sensors deployed along a duct is an inherently non-invasive technique whose feasibility has been demonstrated with a variety of sensors. Until recently, the cost and complexity of the computing equipment which this kind of scheme calls for has militated against its deployment in industry. A fully autonomous system, capable of unattended operation, has now been designed and is being implemented with microcomputer/LSI hardware. The goal of producing online measurements of separate feedrates for a mixed flow is thus within view; much work remains to be done, however, to improve the accuracy of density readings and computations, the speed of computation, durability of sensors and - eventually - reduce the cost of the complete unit.

REFERENCES

1. S. N. Mitra, "A Radio Method of Measuring Winds in the Ionosphere," Ins. El. Eng. London Proc. 96,441, 1949.

2. H. Karplus and A. C. Raptis, "Slurry Flow Measurements Using an Acoustic Doppler Flowmeter," this Symposiumm.

3. C. G. Clayton, "Measurement of Flow of Liquids and Gases Using Radioactive Isotopes", Jour. Brit. Nucl. Energy Soc. 3, 252 (1964).

4. C. G. Clayton, R. Spackman, and A. M. Ball, "The Accuracy and Precision of Flow Measurement by Radioactive Isotopes", Symp. on Radioactive Tracers in Industry and Geophysics, IAEA, Prague 1966.

5. G. V. Evans, R. Spackman, M. A. J. Aston and C. G. Clayton, "Measurement of Gas Flow by Radiotracer Methods", Proc. Internat. Symposium on Modern Dev. in Flowrate Meas. AERE Harwell 1972.

6. G. Taylor, "The Dispersion of Matter in Turbulent Flow Through A Pipe", Proc. Roy Soc. (Lond) 223, 446, (1954.

7. A. J. Favre, "Review of Time-Space Correlations in Turbulent Flow", J. Appl. Mech/Trans. ASME., June 1961, 241.

8. G. Taylor, "Dispersion of Soluble Matter in Solvent Flowing Slowly Through a Tube", Proc. Roy Soc. (Lond) 219, 186 (1953).

9. C. C. Price, J. I. Sackett, R. N. Curran, C. L. Livengood, P. Kehler and G. A. Forster, "Application of the Pulsed-Neutron-Activation Technique for Flow Measurement at EBR-II", ANL-77-52 (Nov. 1977).

10. P. Kehler, "Two Phase Flow Measurement by PNA Techniques", ANL-NUREG-CT-78-17, (1979).

11. C. G. Clayton & J. W. Webb, "The Measurement of Mass Flow and Linear Velocity by a Gas by Continuous Ionization", Int. Jour. Appl. Rad & Isotopes 15, 603 (1964).

12. J. R. Singer and T. Grover, "Recent Measurements of Flow Using NMR Techniques", Proc. Internat. Symposium on Modern Dev. in Flowrate Meas. AERE, Harwell, 1972.

13. R. B. Galloway, "Random Beam Pulsing as a Means of Improving the Efficiency of Some Time-of-Flight Experiments", Nucl. Inst. & Meth. 70, 262 (1969).

14. P. G. Bentley and D. G. Dawson, "Fluid Flow Measurements by Transit Time Analysis of Temperature Fluctuations", Trans. Soc. Instr. Tech. 18, No. 3 p. 183 (Sept. 1966)

15. K. P. Termaat, "Fluid Flow Measurements Inside The Reactor Vessel of the 50 MWe Dodewaard Nuclear Power Plant by Cross-Correlation of Thermo-Couple Signals, Jour. Sci. Instru. 3, 589 (1970).

16. R. S. Flemons, "A New Non-intrusive Flowmeter", Proc. 1977 Flow Measurement Symposium, Feb. 23, 1977, NBS.

17. N. Suzuki, H. Nakabori and M. Yamamoto, "Ultrasonic Method of Flow Measurement in Large Conduits and Open Channels", Proc. Int. Conf. on Modern Dev. in Flow Meas., Harwell 1972.

18. N. N. Kondic, "Indirect Two Phase Flow Measurement: Analysis and Reduction of Errors", 1977 Flow Meas., Symposium, Feb. 23, 1977, NBS.

18a. M. Nagy and K. Varga, "Determination of the Ash Content of Coal by Gamma Transmission", Proc. Symp. on Radioisotope Instr. in Industry and Geophysics, Warsaw 1965.

19. V. M. Thomas and P. J. Becque, "Control Equipment for a Remotely-Controlled Mole Miner", The Mining Engineer 33, 647 (1963).

20. T. C. Piper, "Dynamic Gamma Attenuation Measurements", ANCR-1181 (May 1947).

21. J. T. Ator, "Image Velocity Sensing by Optical Correlation", Applied Optics 5, 1325 (Aug. 1966).

22. K. Porges, "An Online Mass Flowmeter Based on Gamma-Ray Transmission and Correlation", ANL-ZPR-TM-254 (Oct. 1976).

23. U. Fanger, R. Pepelink and W. Michaelis, "Determination of Converyor-Flow Parameters by Gamma Ray Transmission Analysis", IAEA-SM-216/40 Symp. on Nucl. Tech. In Mineral Resources, Vienna 1977.

24. M. S. Beck, J. Drane, A Plaskowski and N. Wainwright, " A New Method of Measuring the Mass Flow of Powder in a Pneumatic Conveyor Using an On-Line Computer", Proc. Conf. on Indust. Tech. for On-Line Computers, London, 1968.

25. M. S. Beck, J. Coulthard, P. J. Hewitt and D. Sykes, "Flow Velocity and Mass Flow Measurement Using Natural Turbulence Signals", Proc. Int. Conf. on Mod. Devel. in Flow Measurement, Harwell 1971.

26. W. Managan, J. Eichholz, and R. Doering, "Field Test of a Capacitive Transducer for Density/Velocity (Mass Flow) Measurements on the HYGAS Pilot Plant Solvent/Coal Feedline," Proc. 1978 Symposium on Instr. and Control For Fossil Demo Plants, ANL-78-62.

27. R. L. Randall, P. J. Pekrul, G. R. Grayban, "Development of Noise Analysis Techniques for Measuring Reactor Coolant Velocity", NAA-SA-71193 (Feb. 1966).

28. B. P. Th. Veltman, "Quantisierung, Abtastfrequenz Und Statistische Steuerung Bei Kprrelationsmessungen", Regelungstechnik, 14/4, 151 (1966).

29. B. Soucek, Laboratory Applications of Small Computers, Wiley, 1976.

30. M. S. Uberio and E. G. Gilbert, "Technique for the Measurement of Cross Spectral Density of Two Random Functions", R.S.I., 30, 176 (1959).

31. M. Bogert, B. Healy and J. Tukey, "The Frequency Analysis of Time Series", M. Rosenblatt, ed., J. Wiley, NY 1963, p. 209 ff.

32. H. Nishihara and H. Konishi, "A New Correlation Method for Transit Time Estimation", Second Specialist's Meeting on Reactor Noise, Gatlinburg, Tenn., Sept. 1977.

33. K. Porges and R. W. Doering, "Mass Flowrate Measurement through Gamma Transmission-Correlation Processing," 1978 Symposium on Instrumentation and Control for Fossil Demonstration Plants, Newport Beach, Cal., June 19-21, 1978, ANL-78-62.

34. R. G. Green, H. K. Kwan, R. John and M. S. Beck, "A Low Cost Solids Flometer for Industrial Use", Jour. Sci. Instr. 16, 1005 (1978).

35. R. A. Fookes V. L. Gravitis and J. S. Watt, "Determination of Ash Context of Coal by Mass Absorption Coefficient Measurements at Two X-ray Energies", IAEA-SM-216/5, Symposium on Nuclear Techniques and Mineral Resources, Vienna 1977.

36. W. W. Managan and R. W. Doering, "Capacitive Transducers for Mass Flow Measurements, An Overview", 1979 Symposium on Instrumentation and Control for Fossil Energy Processes, Denver, Colorado, August 20-22, 1979, ANL-79-62.

37. Przewlocki and P. Nizegorodcew, "Radiometric Measurements of the Parameters of Hydrotransport in Industrial Pipelines", La Houille Blance 28, 59 (1973).

38. M. Michalik, "Density Patterns in Industrial Pipelines Measured by Radiometric Scanning", La Houille Blache, 28, p. 53, 1973.

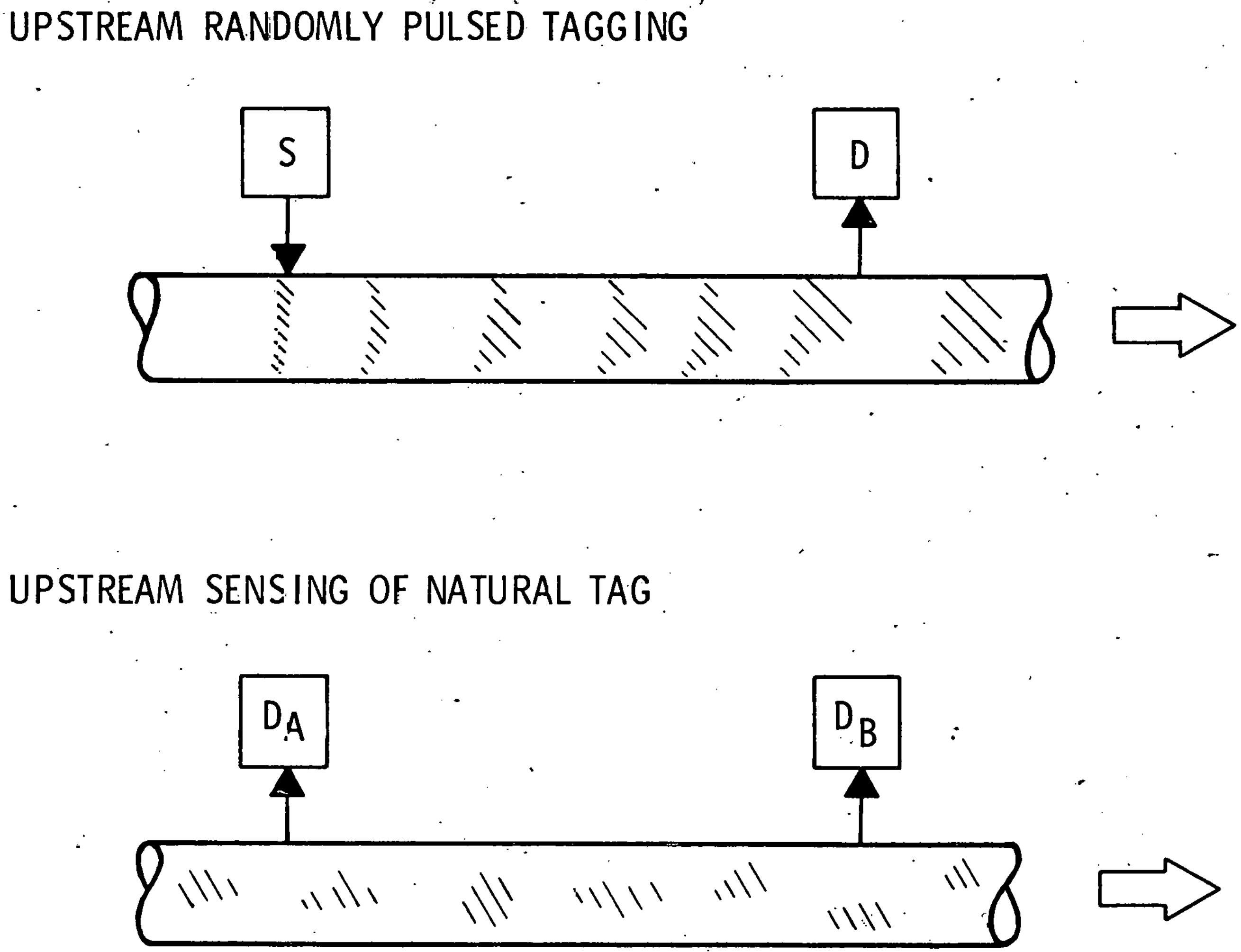


Fig. 1. Random tag (artificial) vs. natural tag.
S = source, D = detector.

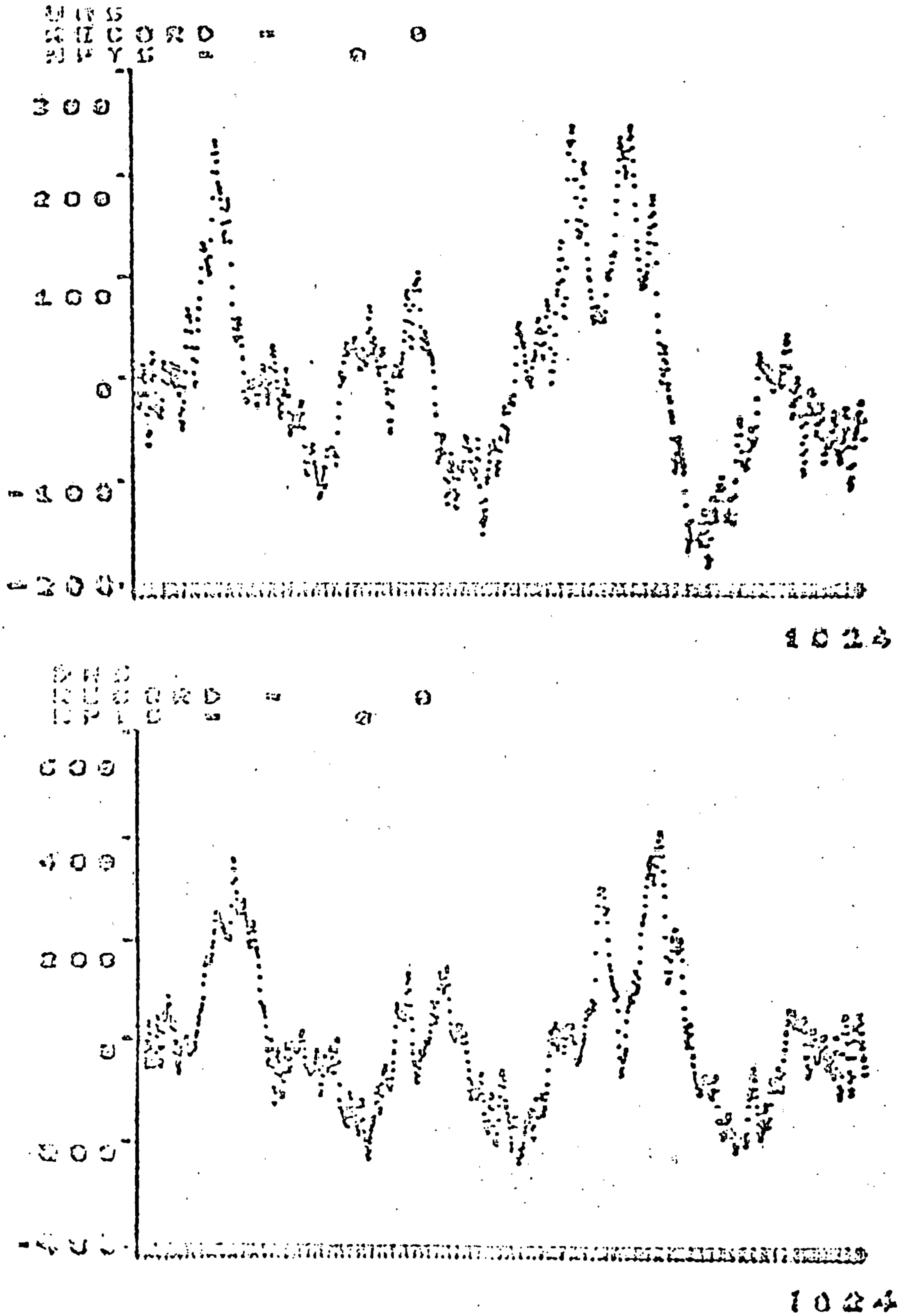


Fig. 2. Typical sample of digitized fluctuations in dielectric constant, resulting from solids clustering in a slurry line; 1-ms samples, average subtracted.

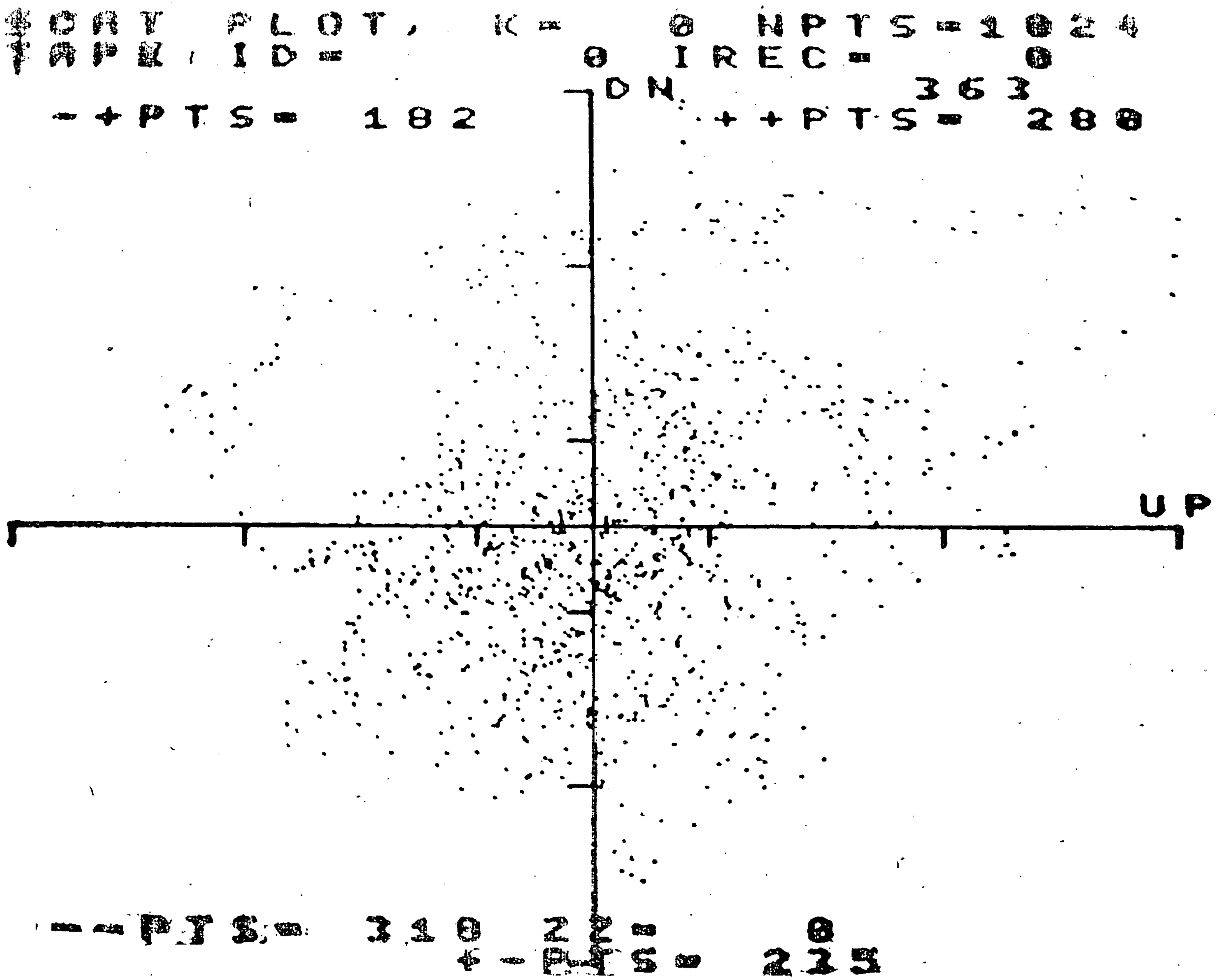


Fig. 3. Scatter diagram of samples shown in Fig. 2, zero lag.

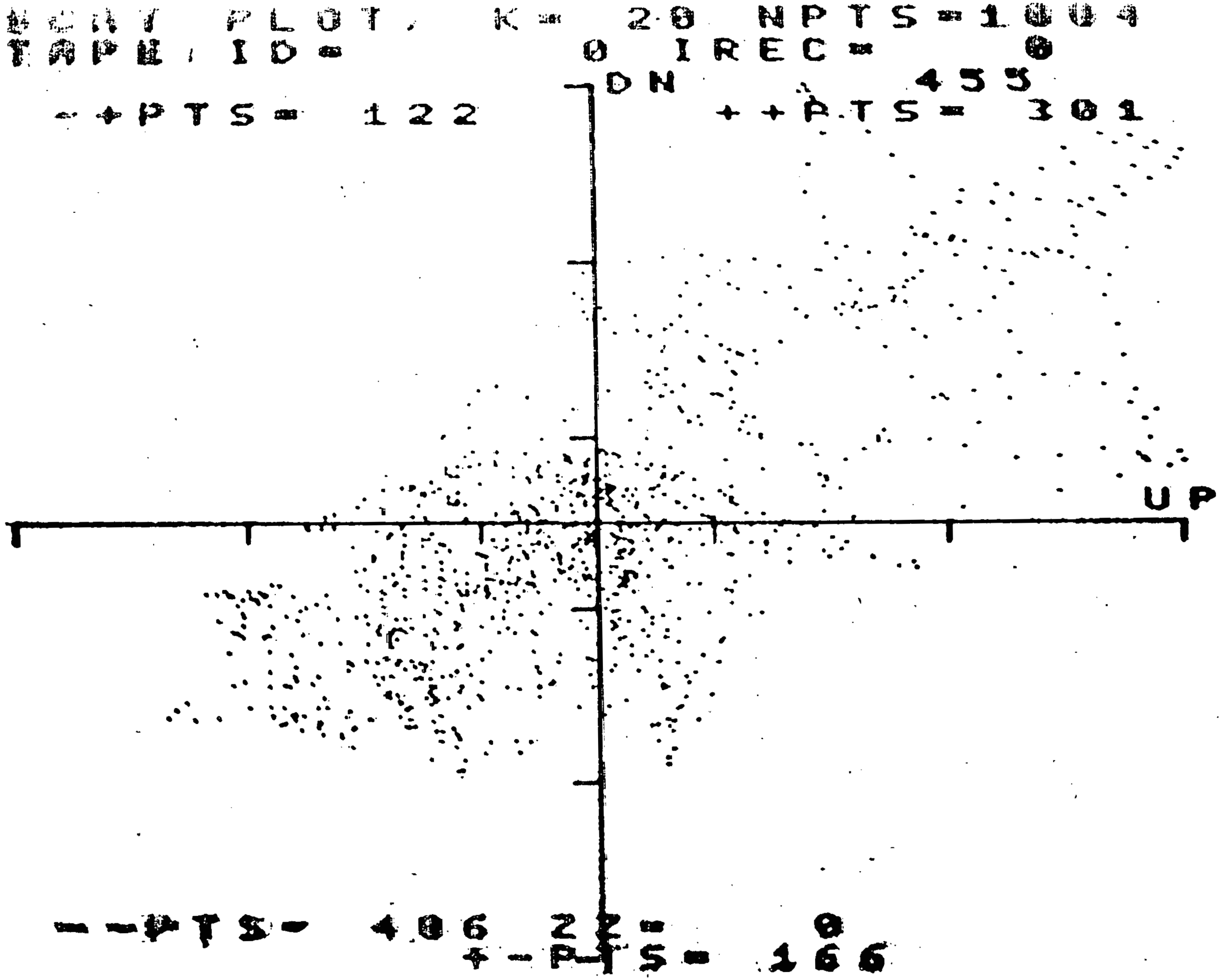


Fig. 4. Scatter diagram, 20-sample (ms) lag.—

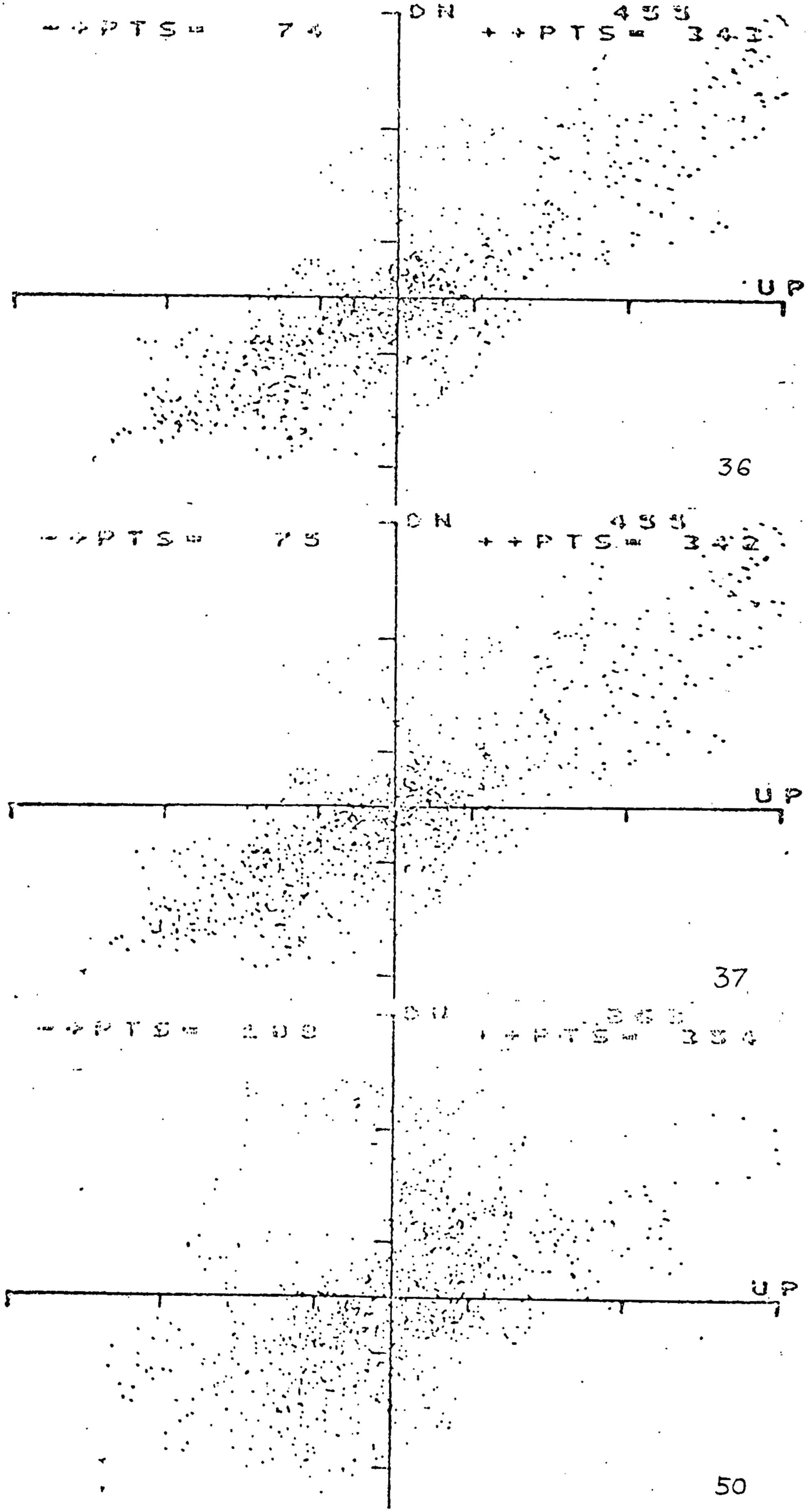
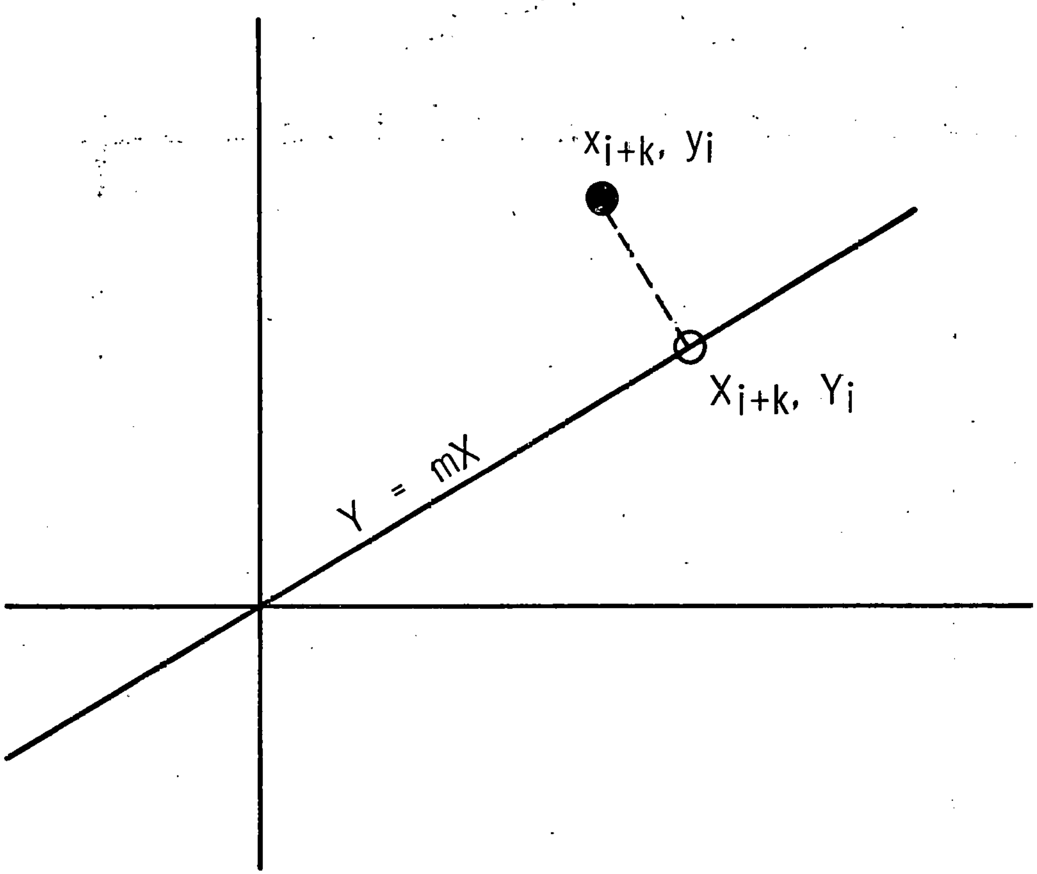


Fig. 5. Scatter diagrams, with 36, 37, and 50 lags.



$$S_k = \sum_{i=1}^{N}\left[(x_{i+k} - X_{i+k})^2 + (y_i - Y_i)^2\right] = (1 + m^2)^{-1} \sum_{i=1}^{N} y_i^2 + m^2(1 + m^2)^{-1} \sum_{i=1}^{N} x_i^2 - 2m(1 + m^2)^{-1} \sum_{i=1}^{N} x_{i+k}y_i$$

Fig. 6. Least squares evaluation of scatter diagram for k-sample lag; the last term equals the covariance.

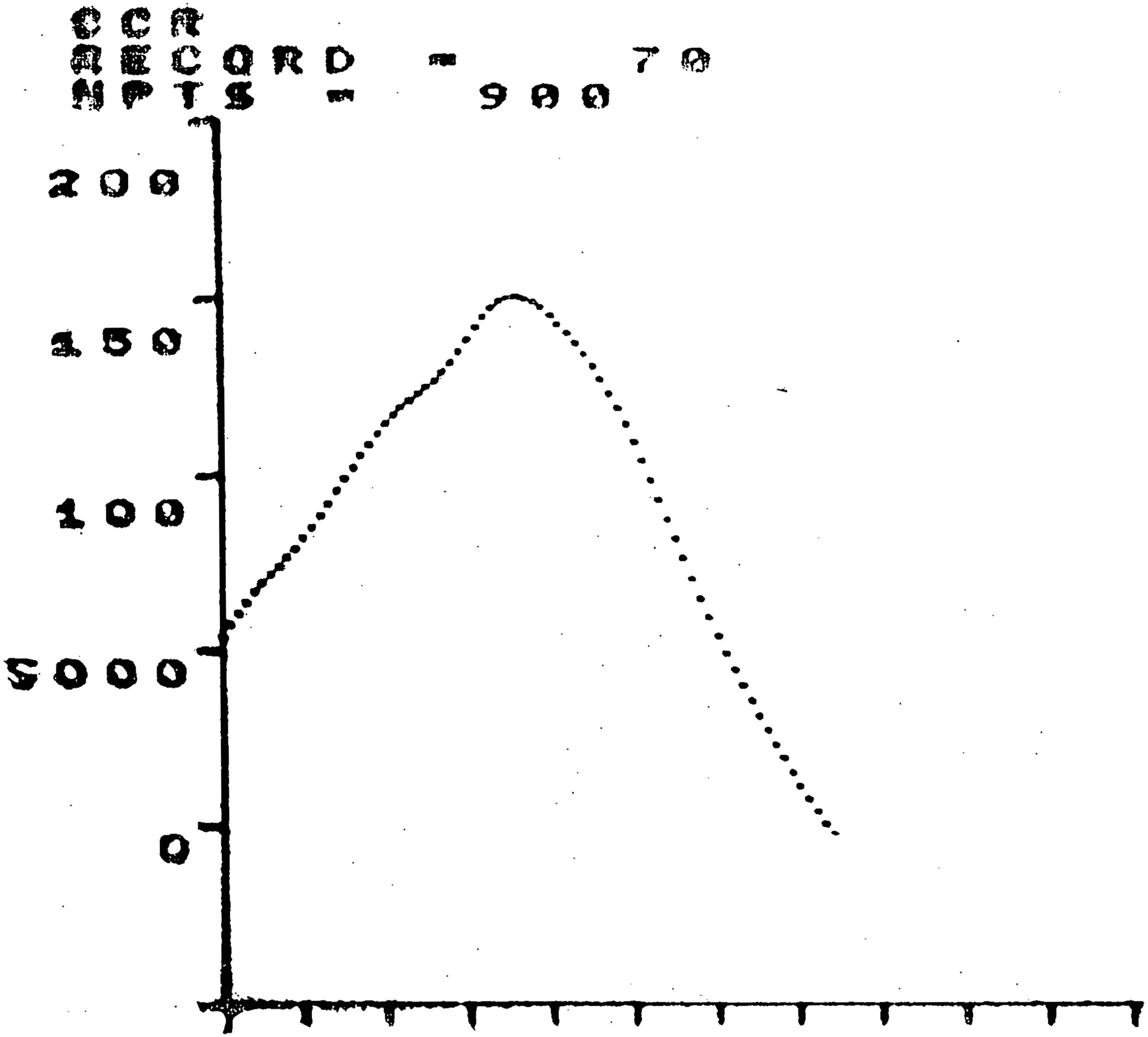


Fig. 7. Covariance term vs lag; this type of plot is also known as "correlogram."

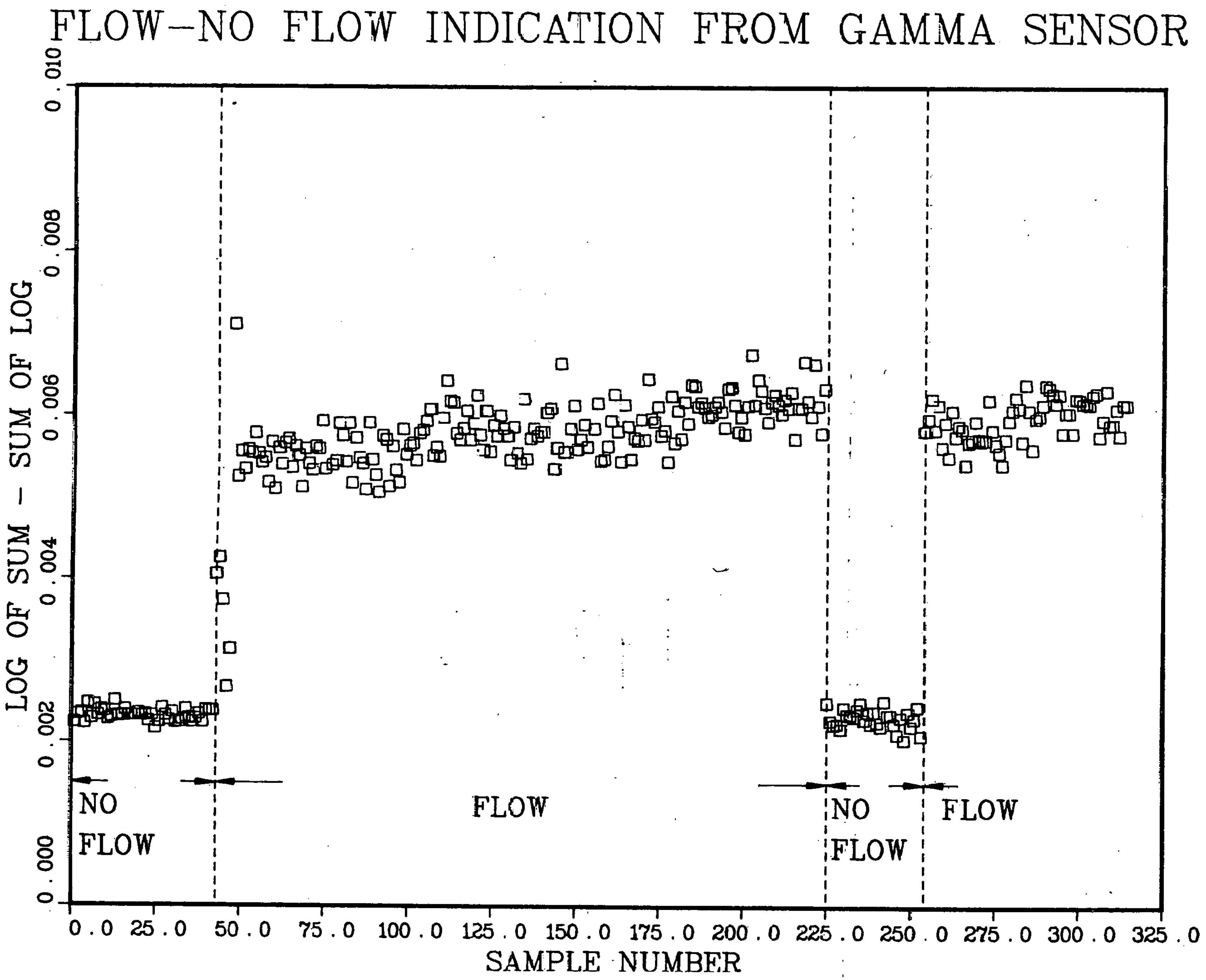


Fig. 8. Sample of FLOW/NO-FLOW statistical indication, obtained with clamp-on gamma (Cs^{137}) transmission on gas/solid line, approx. 5% solids.

TABLE I. Non-invasive Interrogation-Sensing Schemes Suitable for Correlation & Density/Composition Measurement and Online Computation of Mass Flowrate or Component Feedrate

		Source	Detector	Remarks
	(A) TRANSMISSION SCHEMES (Source & Detector on Opposite Sides of Duct			
(a)	Sound	Piezoelectric Xtal	Piezoelectric Xtal	needs coupling medium
(b)	EM Radiation			
(i)	IR/Visible/UV	Laser, LED; Lamp	Photodiode/transistor, PM	needs windows both sides (optical)
(ii)	Xray	Xray Tube; Isotopic	Scint/PM, Ioniz. Ch.	needs Al (Be) windows, both sides
(iii)	Gamma Ray	Isotopic	Scint/PM, Ioniz. Ch.	clamp-on, any duct; needs shielding
(c)	Neutrons	Isotopic	Scint/PM, BF_3 Ch.	clamp-on, any duct; needs shielding; high cost
	(B) EM FIELD SENSING SCHEMES (Electrode Structure Surrounds Duct)			
(a)	Capacitive	RF-driven or DC Bridge; senses κ		sensitive to moisture, temp. dependence of κ
(b)	Inductive	RF-driven coil, senses μ		insens. to moisture; only works with paramagnetic medium
(c)	Conductive	AC or DC electrodes & grounded duct wall		non-quantitative in general, may interfere with flow (produce clustering)

SLURRY FLOW MEASUREMENTS USING AN ACOUSTIC DOPPLER FLOWMETER

H. B. Karplus and A. C. Raptis

Components Technology Division
Argonne National Laboratory
Argonne, Illinois 60439

ABSTRACT

To monitor the flow in abrasive two component mixtures such as coal slurries conventional flowmeters have shown inadequate life and accuracy. Among new techniques being explored, the acoustic Doppler shift flowmeter is particularly attractive for slurry flow measurements. The advantages of acoustic Doppler flowmeters are; 1) Nonintrusive flow measurement on existing systems with nothing except sound waves penetrating in the pipe wall. 2) A linear relationship between the Doppler shift frequency and the flow velocity. 3) A direct output of frequency which is suitable for telemetry and strongly resistant to deterioration by noise. 4) Fast response if extreme precision is not required, but good precision and accuracy if response speed can be waived. 5) Basically simple electronic circuits with minimal requirements of sophisticated components or critical adjustment. 6) An absolute, calculable calibration factor relating output frequency to flow velocity.

Direct calibrations using a weigh tank has confirmed the accuracy of the fundamental Doppler equation. The equation states that the frequency difference, ΔF, between incident and scattered sound is proportional to the flow velocity, V:

$$\Delta F = VF \cos \theta / c$$

The received signal is noisy and exhibits a finite bandwidth instead of a pure tone as implied above. Investigation into the statistical distribution of the variation of the received frequency has shown specific relationships that exhibit the trade off between speed of response and measurement precision. Typically 10% precision can be achieved in 10 milliseconds, but a 0.1% precision requires 100 seconds of integration.

In industrial environments in which hot slurries (over 250°F) are to be monitored, specially developed transducers or stand-off thermally insulating wave guides are useful. Both alternate systems are described.

INTRODUCTION

The ultimate objective of this development program is the design of flow measuring systems for monitoring, mesuring, and controlling the flow of coal slurries in large pipes in coal conversion plants.[1,2,3]

An instrument of interest for this purpose is the acoustic Doppler flowmeter.[4,5] In this system a sonic wave is transmitted in the flow and scattered by the solid particles back to a receiver. The received signal differs in frequency from that of the transmitted signal, F, the difference ΔF being proportional to the ratio of the instantaneous particle velocity component, V cos θ, relative to the sound velocity c. If θ_1 is the angle between the flow and the incident sound beam and θ_2 is the angle between the flow and the scattered sound, then

$$\Delta F = F\,(v/c)\,(\cos\theta_1 + \cos\theta_2) \qquad (1)$$

A Doppler flowmeter was constructed and its performance studied on a simple loop designed and built specifically for this investigation. A weigh tank was used for absolute calibration and statistical analyses were used to predict the precision, response speed, and the possible trade off for diverse specific applications for flowmeters. The acoustic Doppler flowmeter can be retrofitted on existing installations, with electro acoustic transducers mounted on the outside of existing pipes, with nothing except the sound energy penetrating the pipe wall. Special high temperature transducers have been developed at ANL for flow measurement of hot fluids. As an alternative, thermally isolating waveguides may be used with less costly transducers. We are preparing to demonstrate the system on a hot slurry line at a Solvent Refined Coal (SRC) pilot plant. The components of the system have been tested and we feel confident for a successful demonstration.

Investigations to date have concentrated on the Doppler meter characteristics to determine operating characteristics such as accuracy, precision, response speed and effects of the slurry properties on these parameters.

THE CIRCUIT

The simplicity of the electronic circuit shown in Fig. 1 is among the attractions of this instrument. It consists of an oscillator, a receiver amplifier, a mixer and a signal conditioner. The mixer used was a commercial double balanced mixer fed with a small fraction of the transmitted signal. Most of the time sufficient leakage of the transmitted signal into the receiver causes this to appear like an amplitude modulated signal, permitting simple diode demodulation to yield the difference of frequency. Occasionaly the scattered signal was stronger than the leakage signal resulting in an overmodulated signal, which, with a simple diode, yielded twice the Doppler frequency. The commercial availability of low cost double balanced mixers makes their use attractive for the Doppler flowmeters, permitting high amplifier gain and good rejection of extraneous noise.

The output of the demodulator is then further processed by a circuit that rejects small amplitude spurious high frequency noise. This is accomplished with a comparator having a small amount of hysteresis obtained with negative feedback from the output. The signal looks like a variable amplitude variable frequency sine wave contaminated with some high frequency noise. The measurement of the frequency is distur-

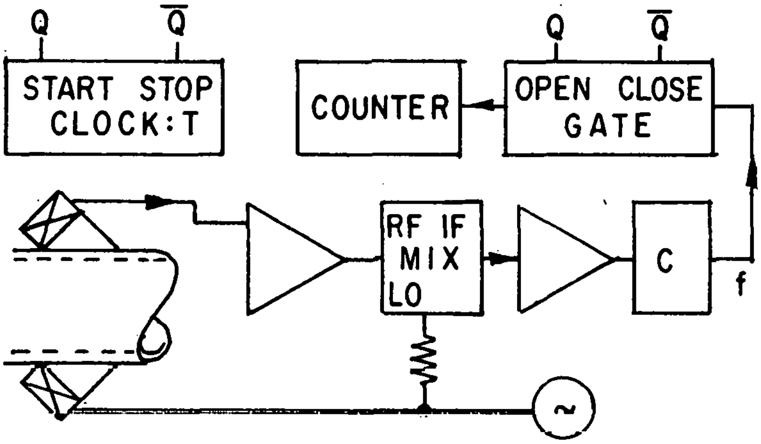


Fig. 1 Block Diagram for the Doppler Flowmeter

bed by the variability of the amplitude and the superimposed high frequency noise. A counter set for the detection of the zero crossing will occassionally yield additional counts due to noise. A judicious choice of hysteresis eliminates this problem, provided the threshold is not so large that the smaller amplitude signals are omitted.

TRANSDUCER MOUNTING

One of the great advantages of the acoustic Doppler flowmeter is the ease of installation. In many applications it is feasible to simply attach transducers to the outside of the pipe and transmit the sound directly through the wall. At room temperature, relatively simple cleaning of the pipe wall makes fluid coupling between transducer wedge and pipe practical. For permanent installations an epoxy bond is convenient. Transducers may also be mounted inside the pipe or the sound may be transmitted through "windows". For internally mounted transducers, servicing is a problem which can be solved with ball valves mounted on tee's. Window mounted transducers need to be backed with adequate pressure barriers.

There is another variation of the doppler flowmeter to be just mentioned in passing, for use on invivo blood flow. These flowmeters differ from the system described here by utilizing sound transmission in bursts and time gated reception to relate the scattered energy to a specific vessel under the skin.

Time gated velocimetry looks interesting for flow profile studies, but will be limited in resolution by the upper frequency range imposed by attenuation in dense slurries. Ambiguities also arise from multiple reflections in the pipe wall. Flow profile research with Doppler techniques needs immersed transducers.

Experiments[4] to date have been confined to direct external attachment of wedge mounted transducers with preparatory design for adaptation to hot pipes. For work at room temperature, conventional transducers, such as the ones widely distributed for nondestructive testing, were mounted on Lucite wedges. Wedges were designed so that sound waves in the pipe wall propagated in the shear mode. A simple mode propagation is thereby assured. Some signal strength improvement was obtained by using a wall thickness coincident effect to get in phase propagation after each reflection. This amounts to tunning the operating frequency to have a wave length in the wall equal to W sin α, where W is the wall thickness and α the propagation angle with the pipe axis. The effect is that the transducer images produced by multiple reflections in the pipe wall act as a phased array which has a narrower beam pattern. For the experimental arrangements on a 2 inch schedule 40 pipe with 3.9 mm wall, a lucite wedge was fabricated having 23.7° angle, giving coincidence frequencies of 457 kHz and multiples of that frequency. A thicker pipe, 2 1/2 inch schedule 160 pipe having a 9.5 mm wall of type 304 stainless steel was fitted with a 33.9° wedge giving coincidence frequencies of 214 kHz and multiples of that frequency. The output signal was enhanced at the coincidence frequency. The technique shows promise to be especially effective on large pipes.

HIGH TEMPERATURE APPLICATIONS

We advocate two different approaches to the problem of measuring flow of hot slurries. In the first approach we utilize specially designed transducers[6] made entirely out of materials capable of withstanding high temperatures as shown in Fig. 2. In the other approach we use stand off wave guides to transmit the sound through the temperature gradient. Both approaches are aimed at single wall pipes. Pipes with ceramic liner that may introduce special sonic conduction problems are beyond the present scope. For these, some form of immersion or window may be required.

The high temperature transducers were developed for a different type of sonic flowmeter[7] useable in pure fluids where the absence of scatterers makes the doppler flowmeter useless. These transducers were designed for measuring the flow of pure sodium in a 300 mm (12 inch) pipe. A time difference acoustic flowmeter has been operating with negligible change in sensitivity since April 1978 at a temperature of 465°C (870°F) with monthly cycles to 300°C (570°F) and one cycle to room temperature (fluid drained). Transducers for the operation of a doppler flowmeter would be basically similar with some simplifications to cut costs. A lower operating frequency will also be needed.

The high temperature transducers differ from the room temperature transducers in several respects.

1. The wedge is made of 304 stainless steel.

2. The transducer element is X-cut Lithium Niobate, generating shear waves directly without mode conversion.

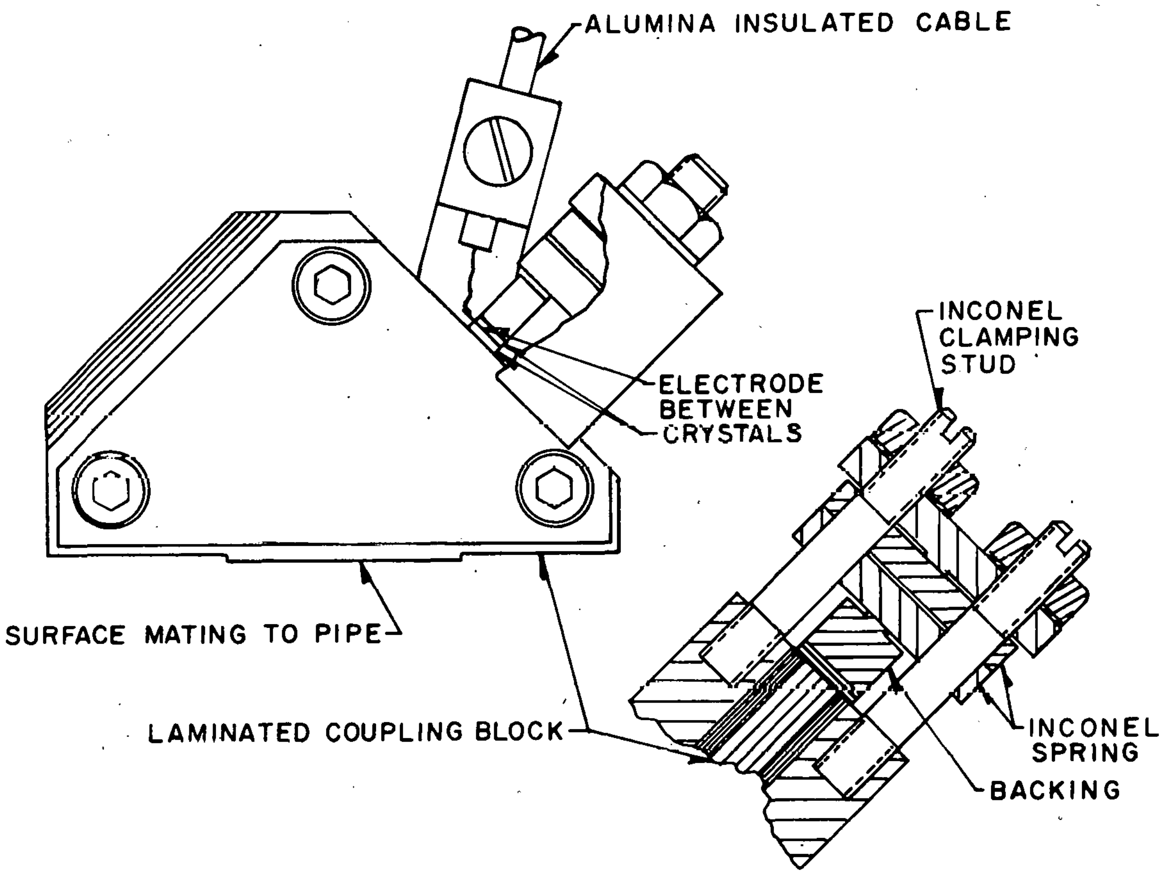


Fig. 2 Ultrasonic Transducer on a Laminated Coupling Block

3. The transducer element is coupled to the wedge through a soft Platinum foil and clamped with a force of ten Mega pascals (1500 psi) using Inconel leaf springs.

(Simple clamps were found to relax after a long time at the high temperature due to material creep. Differential temperature coefficients cause crystals to crack if cements are used.)

Transducers for the time difference acoustic flowmeter were resonant at about 3 MHz. Lower frequency transducers (1 MHz) having a reasonable high electrical admittance were also constructed using thin transducer plates backed by a suitable thickness of Tungsten Carbide. The same design approach will be taken for similar transducers to be constructed for a Doppler flowmeter for high temperature slurries. The transducer wedge may be attached to the pipe by brazing or clamping. We have used a clamping system which enabled us to remove the transducers easily. Not having found a fluid couplant with an extended life at 465°C, gold foil was used as a couplant between optically flat surfaces. A contact force of about 3000 N (600 lbf) was applied via a long Inconel leaf spring to produce the necessary contact pressure without distorting the thin wall pipe.

Operation of the transducers at high temperature to 600°C (1100°F) has been demonstrated in a furnace for a few days. The Curie temperature of the Lithium Niobate is 1200°C. This represents an upper limit for this design. Even at temperatures well below this the intrinsic conductivity of the crystal would require design modification to offset the shunting effect of this conduction current.

The alternative approach is the use of stand-off thermal isolators shown in Fig. 3. For moderate temperature (250°C, 500°F) polyimide (Vespel) can be used to separate a cooled transducer from a hot pipe. At higher temperatures, metal and ceramic standoffs have been designed. Conventional mode conversion using a wedge to generate shear waves will reduce multimode propagation in the wave guides and yield more favorable angles for the beam in the slurry. Two forms of wave guides are shown. The one in the middle conducts the sound wave in the desired direction directly into the pipe. The wave guide on the left uses the reflection property of a free surface to permit a shorter path. A pair of guides of this type has been fabricated and is currently awaiting arrival of wedges and transducers for testing prior to pilot plant installation. Steel wave guides will be brazed to the steel pipes.

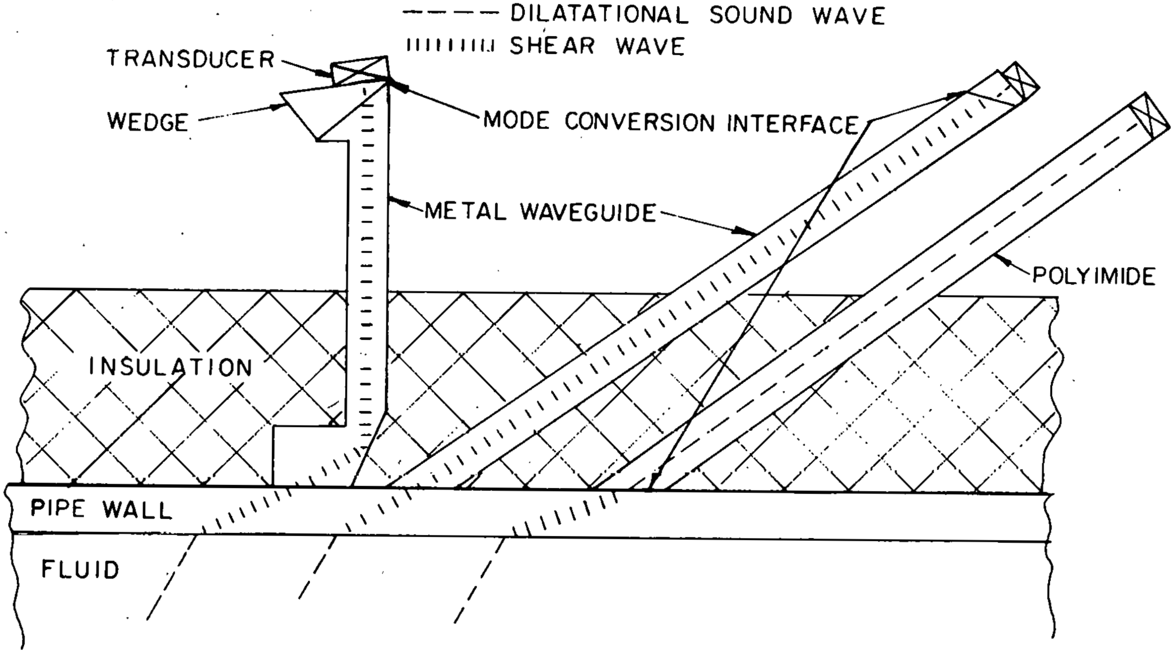


Fig. 3 Three Forms of Thermally Isolating Waveguides

Ceramic wave guide attachments using combinations of ceramic cements and clamping systems have been demonstrated on another project to about 100 kHz. Extension of this technique to this program is planned for the near future. Ultimately we anticipate that the combination of wave guides with transducers capable of moderate temperatures will be more cost effective than the high temperature transducers for the Doppler flowmeter.

CALIBRATION

Our investigation included the calibration and characterization of the received signal to permit performance specification. The Doppler flowmeter was calibrated using a weigh tank. A pump circulates the slurry through the piping system via a series valve and a parallel bypass permitting adjustment from no flow up to about 5 liters per second (80 gpm). A pair of mechanically connected ball valves permits discharge of the flow to be diverted from the reservoir to a weigh tank. The weigh tank is suspended from a force gauge and a mass is hung from the tank.

To measure flow rate, the flow is diverted into the weigh tank. As the voltage output from the force gauge increases, a clock is started at a preset trip level. While the fluid accumulates in the tank, the weight suspended from the tank is removed. When the quantity of fluid which has been accumulated in the tank is identically equal to the mass removed, the same trip level is reached again, and the clock is stopped. Mass flow rate is then the quotient of mass of suspended weight divided by the time interval measured. Besides connecting the trip comparator to a clock, the output was also connected to a gate through which the zero crossing pulses of the Doppler meter were passed to a counter. The frequency of the Doppler meter was thus integrated over precisely the same time interval over which the weigh tank measurement was integrated. Systematic errors are therefore limited to the non linearity of the flowmeter within the range of flow loop velocity fluctuations and the determination of mass and time. These errors are very small compared with the statistical uncertainties of the frequency measured.

A calibration obtained in this way is shown in Fig. 4. The mass was set at 70 kg. The total number of counts, N, about 3000 was independent of flow rate. Measurement duration varied from 10 to 200 sec. The regression line shows a small discernible zero offset which needs compensation in a measuring instrument. This effect is attributed to residual noise which was not completely eliminated.

RESPONSE AND PRECISION

The received signal, as already stated, is not a pure tone but a band of noise surrounding the tone. A convenient way of characterizing this bandwidth[4] for performance analysis of the flowmeter is the statistical distribution of the period of the Doppler signal. When the period is averaged for a number of cycles, the standard deviation of this average will be equal to the product (σ x N) of the standard deviation of the period and the square root of the number of cycles averaged. This leads to the integration time, T, required for any desired precision, E, given the mean Doppler frequency, F, and the relative standard deviation of the frequency, S - σ/F.

$$T = S^2/E^2F \qquad (2)$$

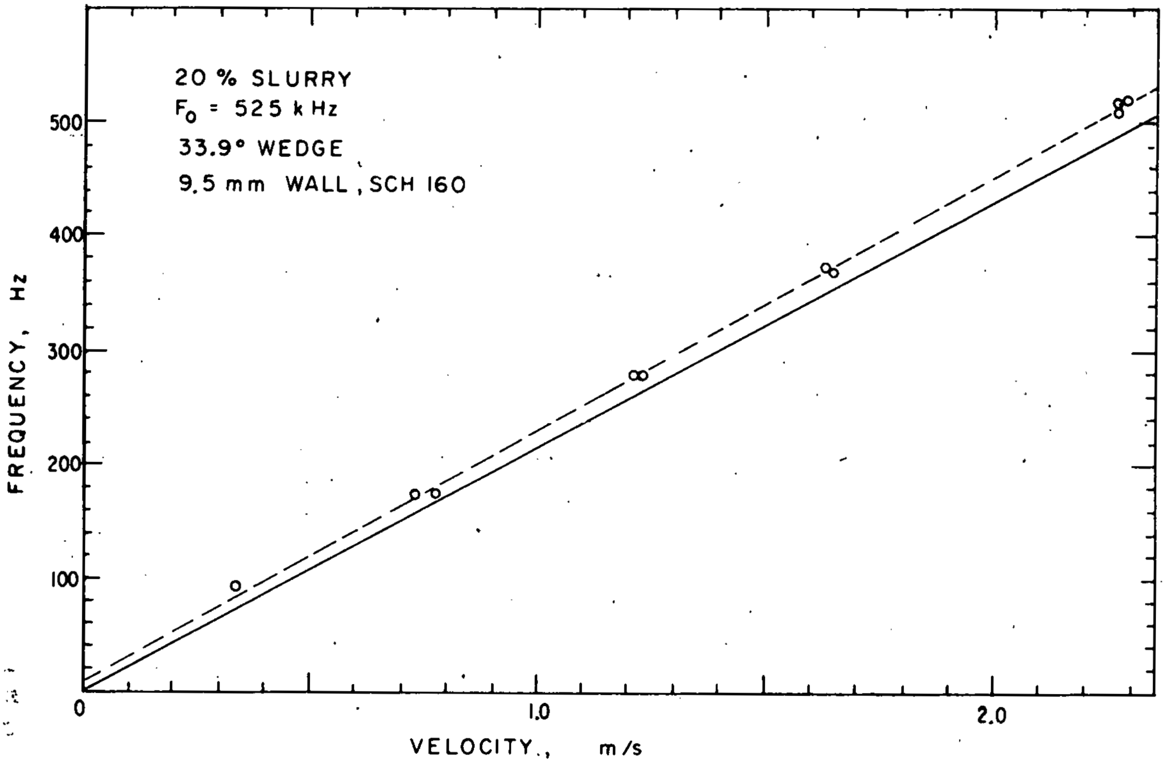


Fig. 4 Doppler Flowmeter Calibration

The integration times required for specified precision are listed in Fig. 5 for $S^2 = 0.1$. Flow readings of modest precision (10%) are very quickly obtained, but high precision measurements, especially at low flow rates, take a long time to accumulate.

Table 1

$$T = S_1^2 / E^2 F \qquad S_1^2 = 0.1$$

E %	COUNT RATE, F		
	1000Hz	200Hz	100Hz
10	.01	.05	0.1
1	1	5	10
.1	100	500	1000

Fig. 5 Integration Time, Seconds

The relative standard deviation of the period i.e., the ratio of the standard deviation to the mean value of the period was determined for the two pipes over a range of flow from 0.2 to 2 ms^{-1} and for operating frequencies from 250 to 2500 kHz. In Fig. 6 the relative standard deviation is plotted as a function of flow rate and shows minimal variation with this parameter. Similarly the plot in Fig. 7,

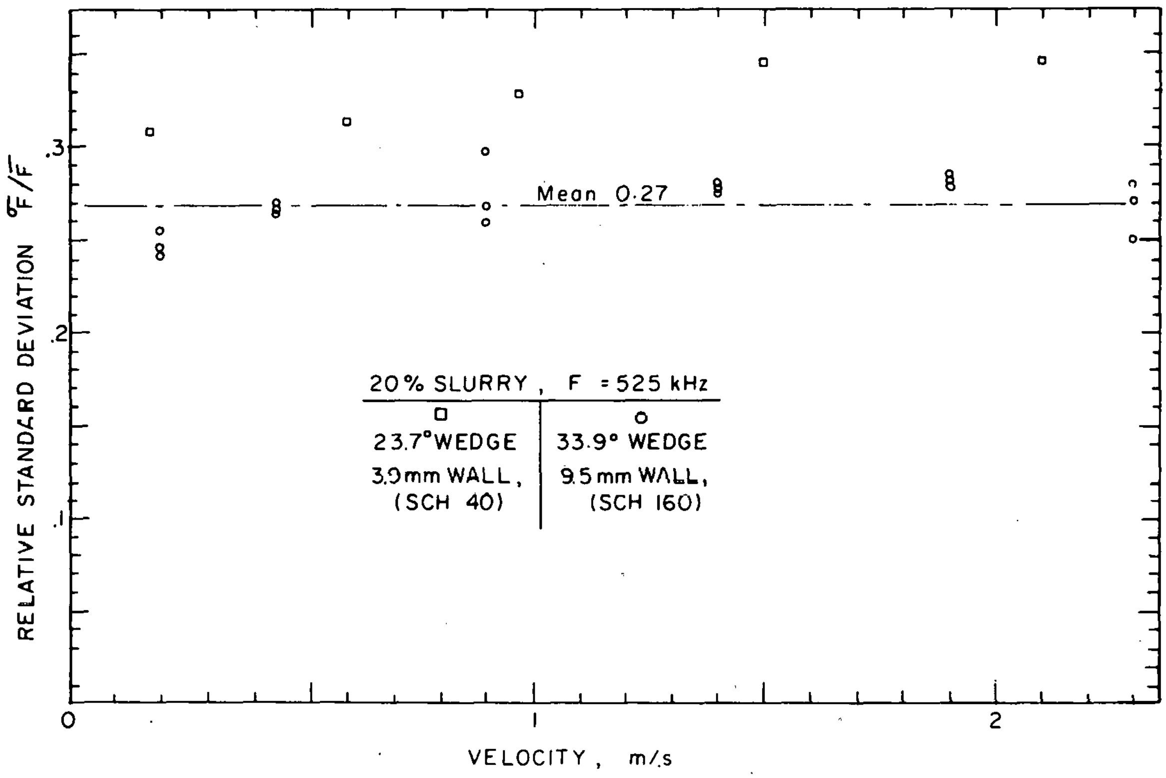


Fig. 6 Relative Standard Deviation of Doppler Frequency

of relative standard deviation as a function of operating frequency shows only small effects of the operating frequency on the relative standard deviation. There may be small dips of the coincidence frequency of 460 Hz for the 23.7° wedge on the 3.5 mm wall (Sch 40) pipe. Further detailed investigation of this question will be needed especially more detailed data will be desirable on the thicker wall pipe with the 33.9° wedge.

Both Figs. 6 and 7 show a significantly lower relative standard deviation with the 33.9° wedge than for the 23.7° wedge. Tentatively the effect is attributed to the small (23.7°) angle of incidence which gives rise to both shear as well as dilational waves in the pipe. The 33.9° angle in the lucite wedge gives rise to pure shear waves in the pipe, the dilatation wave being beyond the critical angle. This leads to the conclusion that the coincidence angle must be chosen to be greater than the critical angle for mode conversion to pure shear waves.

The bandwidth of the Doppler signal is attributed to three sources.

(a) The change of phase of the received signal produced by the detailed rearrangement of the scatterers by the flow.

(b) The width of the sound beam.

(c) Real rapid flow fluctuations.

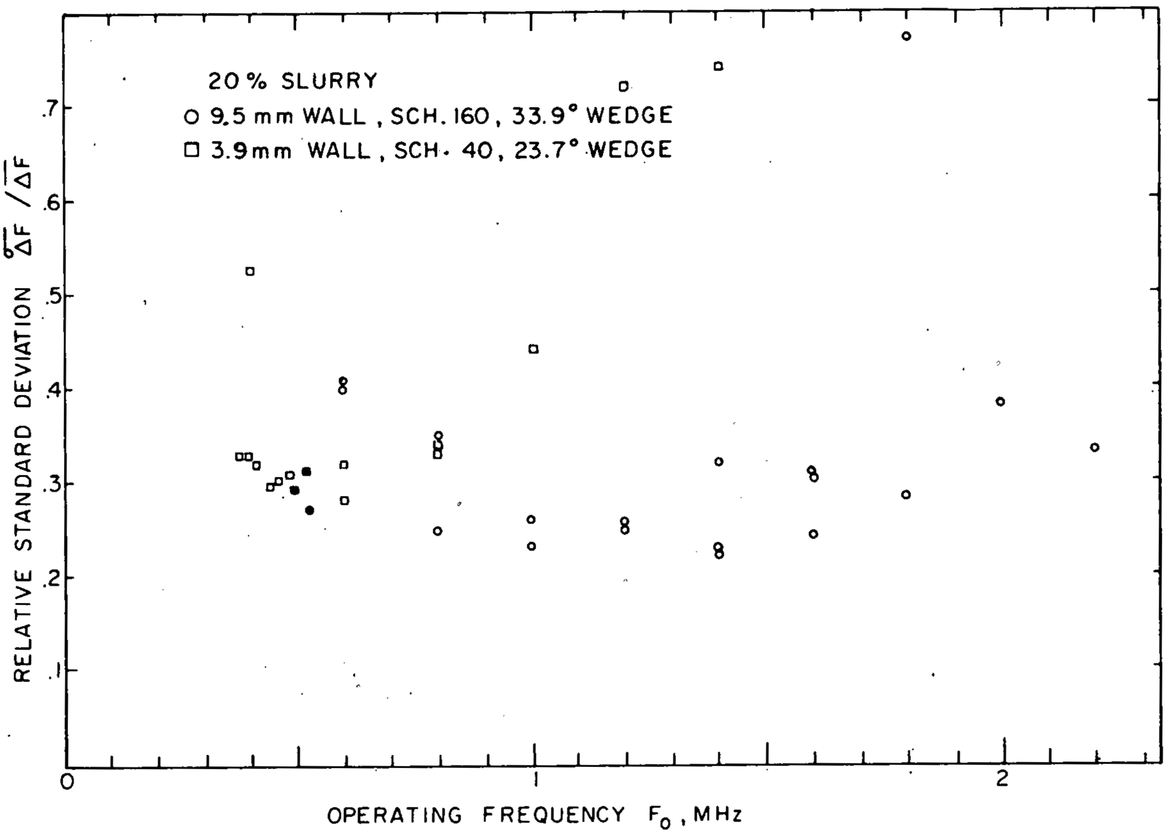


Fig. 7 Relative Standard Deviation of Doppler Frequency

A theoretical analysis of the sources of band spread would help in determining their relative importance and lead to further improvements on the Doppler flowmeter. This study has lower priority than the demonstration of the flowmeter on hot pipes.

CONCLUSION

In summary the Doppler flowmeter yields predictable flow measurement rapidly with modest precision or with better precision (fractional percent) after minutes of averaging. Applications to hot slurries will be demonstrated soon. Components of a high temperature Doppler flowmeter have been tested, assuring success for the demonstration.

ACKNOWLEDGEMENT

The authors wish to express their appreciation to T. K. Lau of DOE-FE for his cooperation and suggestions. The construction of the weigh tank apparatus and flowmeter electronics was performed by a summer student, Ira Pollack. We also acknowledge the cooperation and support of T. P. Mulcahey, N. M. O'Fallon, G. A. Forster and P. D. Roach.

REFERENCES

1. N. M. O'Fallon, R. A. Beyerlein, W. W. Managan, H. B. Karplus and T. P. Mulcahey, "A Study of the State-of-the-Art of Instrumentation for Process Control and Safety in Large-Scale Coal Gasification, Liquefaction, and Fluidized-Bed Combustion System, ANL-76-4, January 1976.

2. A. C. Raptis, J. W. Fitzgerald, G. F. Popper, R. Doolittle and S. H. Sheen, "A Feasibility Study of Acoustic/Ultrasonic Flowmeters for Solid/Gas Systems, ANL-FE-49622-TM01, March 1978.

3. Instrumentation and Process Control for Fossil Demonstration Plants, Annual Technical Progress Report, ANL-FE-49622-12, October 1976 - September 1977.

4. H. B. Karplus and A. C. Raptis, "Flow Measurements of Dense Slurries Using the Sonic Doppler Principle" IEEE 1978 Ultrasonic Symposium Proceedings, IEEE Cat. #78, CH1344 - ISU.

5. H. B. Karplus, A. C, Raptis, "Investigation Leading to the Development of an Acoustic Doppler Slurry Flowmeter ANL-FE-49622-TM06, (1979).

6. H. B. Karplus, "Ultrasonic Transducer With Laminated Coupling Wedge", U.S. Patent 3,973,152 - Dec. 1976.

7. H. B. Karplus and G. A. Forster, "Interim Ultrasonic Sodium Flow Measurement on the EBR-II Secondary System", ANL-CT-78-23, March 1978.

AN ACOUSTIC CHAR FLOW MONITOR FOR THE BI-GAS PILOT PLANT

P. D. Roach and A. C. Raptis
Components Technology Division
Argonne National Laboratory
Argonne, Illinois 60439

ABSTRACT

The BI-GAS coal gasification pilot plant at Homer City, PA has an urgent need for monitoring char flow to the gasifier. An undetected flow stoppage can very quickly cause a dangerous temperature excursion in the gasifier. At the request of BI-GAS,the Argonne National Laboratory (ANL) has developed and installed acoustic monitors which give rapid indication of blockages or other flow perturbations in the char lines. These monitors use a high temperature microphone, developed at ANL, for measuring the acoustic attenuation caused by the presence of char in the line. Such a measurement gives an indication of the amount of char flowing in the line and can be used for rapid detection of blockages and possibly process control.

1.0 INTRODUCTION

The BI-GAS coal conversion process is being developed by Bituminous Coal Research, Inc. at its pilot plant in Homer City, PA. The process involves two-stage high pressure coal gasification in an entrained bed type of reactor, shown schematically in Fig. 1. Powdered coal is fed to an initial (upper) stage where it is devolatilized and partly gasified as it contacts the hot gases rising from the lower stage. The gas and char (partly reacted coal) are separated in a char cyclone and the char is reintroduced into the gasifier in the lower stage. In this stage, the char reacts with steam and oxygen under much hotter conditions (1370° - 1650°C, 2500° - 3000°F). The residue, or slag, is molten at this temperature and flows to the water cooled quench zone, while the hot gases rise to the upper section of the gasifier. After passing through the char cyclone, the gases go to a shift reactor and fluidized bed methanator to produce a high BTU pipeline quality gas.

The instrumentation needs at the BI-GAS plant are fairly typical of those throughout the coal conversion field. In particular, flow monitors are needed that can handle the multiphase process streams. These streams are frequently at high pressure and high temperature and are very erosive. Available flowmeters are usually not able to withstand such a hostile environment.

Of particular concern at the BI-GAS pilot plant is monitoring the char flow. Blockage of the char feed lines between the char cyclone and the char burners has been a recurrent problem. The char first drops approximately 16 meters by gravity feed from the cyclone to a steam eductor

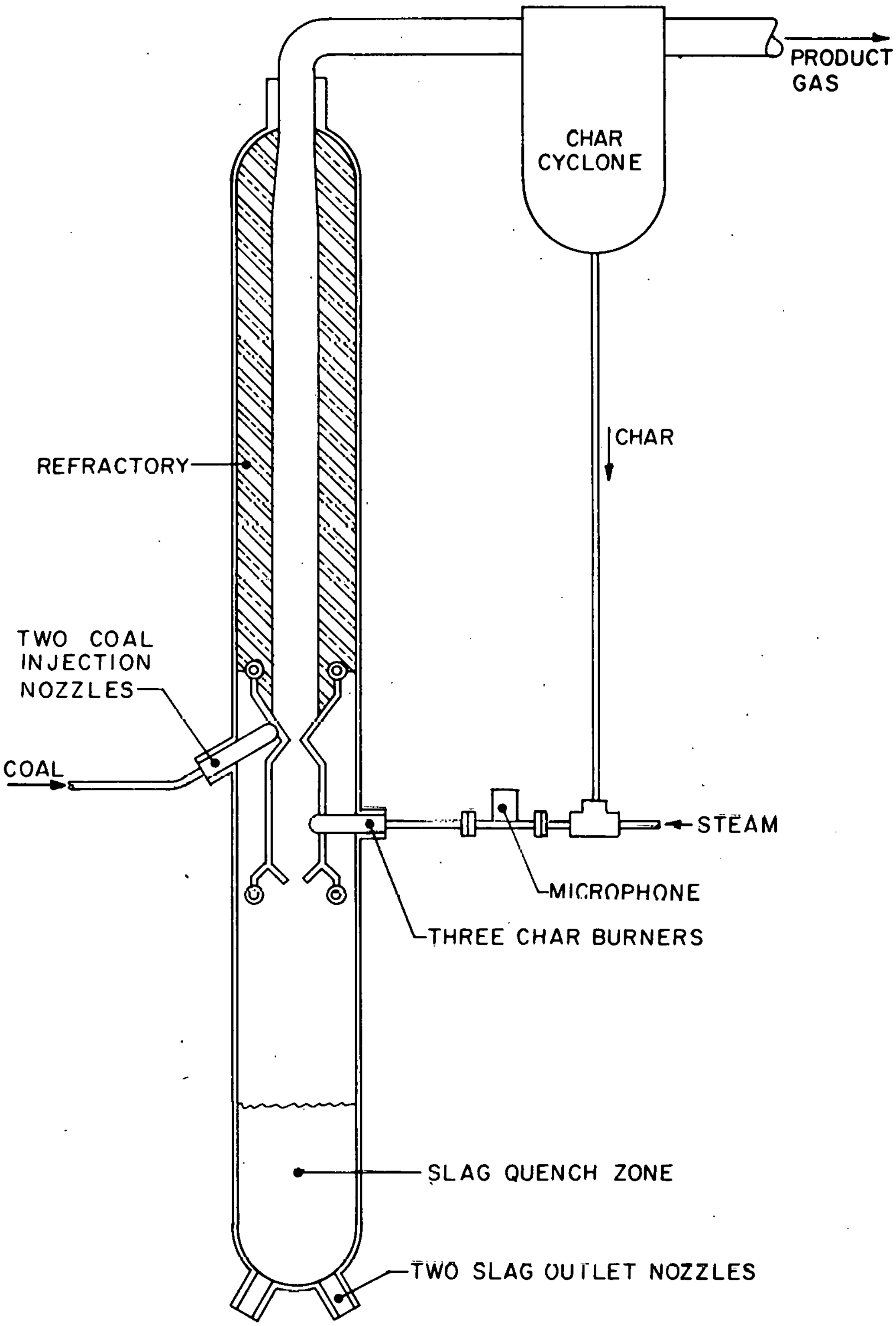


Fig. 1 Schematic Diagram of BI-GAS Reactor

where high pressure steam is added to the char. The char and steam then move horizontally about 3 meters to the nozzle of the char burner. Blockage of the char in either the vertical or horizontal section can cause a very serious perturbation of the gasifier operation and can quickly lead to a hazardous temperature excursion in the gasifier.[1]

The safety aspects of this problem made the need for a flow monitor quite urgent, but no commercially available unit was known that could do the job.[2] The design operating conditions in the char line are temperature of 430°C (800°F) and pressure of 11.4 MPa (1650 psi). The char particles are quite abrasive and also tend to plug orifices and to foul moving parts. Because of these difficulties, BI-GAS requested the assistance of Argonne in developing a suitable flow monitor. The group at ANL which has responsibility for instrumentation for coal conversion plants suggested several possible solutions. The acoustic monitor described in this paper was chosen as being the most promising approach, especially in view of the urgency.

2.0 DESIGN CONCEPT

Based on preliminary pilot plant measurements with no char flowing[3], it was evident that the steam eductor is a major source of acoustic noise. A microphone in the location shown in Fig. 1 produced a strong, broad-band signal associated with the steam flow. This meant that the presence of char could be judged in two different ways: first, by looking at the reduction of the steam signal caused by scattering from the char particles,[4] and second, by looking at noise added by the char flow (caused by impingement of particles on the pipe and microphone).[5]

The combination of a relatively streamlined geometry (to minimize flow obstruction and microphone erosion) and a large steam signal strongly favors the first mode. The second mode would be favored with a geometry that caused more particle impingement on the microphone or in a situation with much less background noise. The first mode dominates in the present situation and forms the basis for understanding the observed data.

In effect, the geometry in the char line allows us to make an attenuation measurement on the char. The steam eductor serves as a constant broadband noise source and the pipe section between it and the microphone is the attenuation path. The presence of the char particles will cause absorption and scattering of the acoustic energy generated by the steam eductor, giving a decrease in the observed microphone signal. The amount of this decrease will be an indication of the amount of char present in the line. Thus, the apparatus will not only indicate positively whether char is flowing or not, but also will give an indication of the amount that is flowing. This indication will relate only to the char density, however. An additional measure of the char velocity is necessary to obtain mass flow rate.

3.0 INSTRUMENTATION

The microphone chosen for this application is a rugged high-temperature unit developed in the Components Technology Division of ANL.[6] As shown in Fig. 2, it uses two identical plates of lithium niobate arranged back-to-back

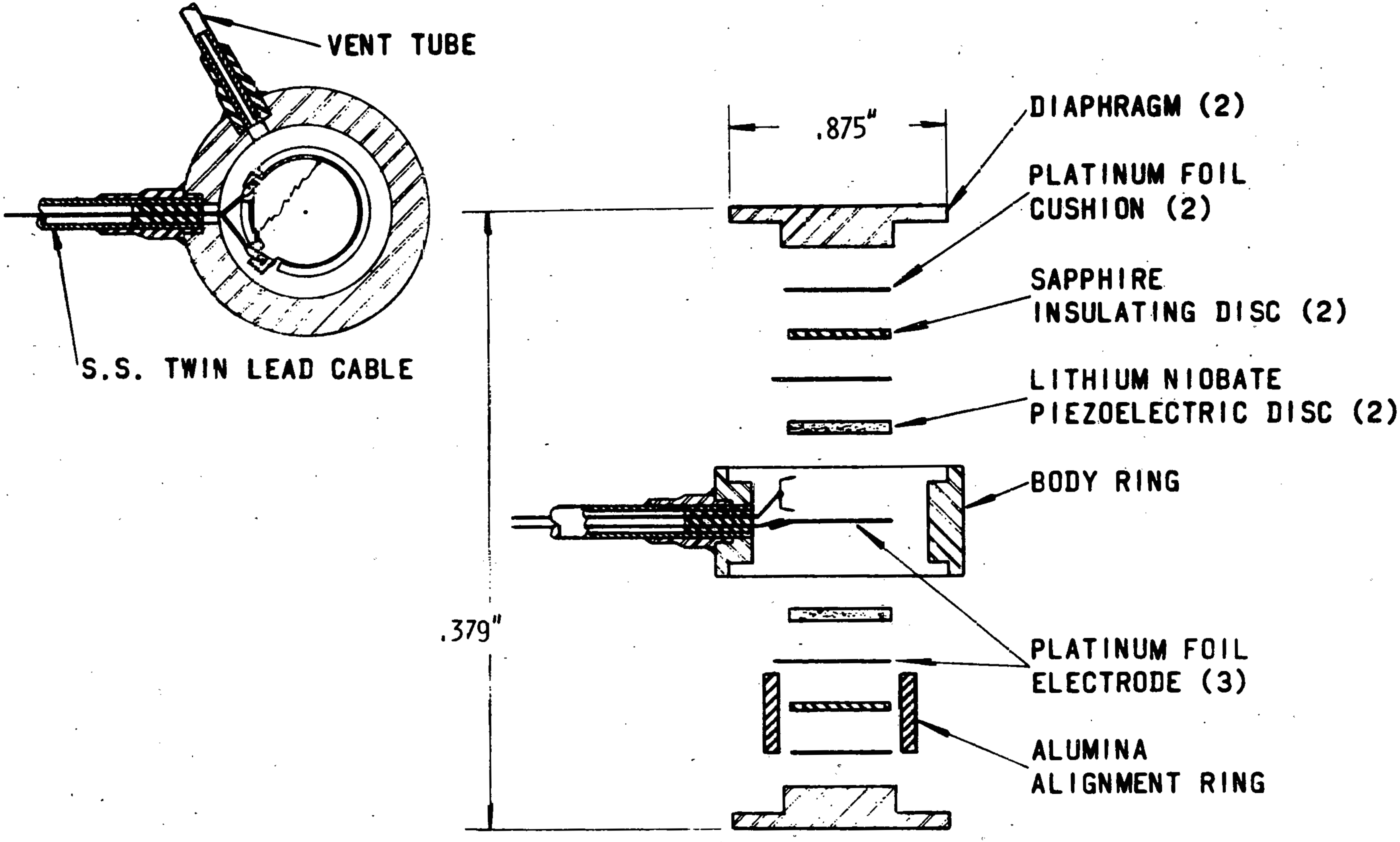


Fig. 2 Construction Details of High-Temperature Microphone

with respect to their piezoelectric polarities. This makes the microphone sensitive to pressure changes on the faces but it is relatively insensitive to vibration of the device as a whole. This design means the microphone cannot be clamped to the outside of the pipe but must be immersed in the flow. Fortunately, this microphone is well suited to withstand the severe process conditions, since it is completely encased in type 304 stainless steel and is capable of operating at temperatures up to 650°C (1200°F) and pressures up to 14 MPa (2000 psi). The frequency response of the microphone is fairly constant from 100 Hz to 50 kHz, but is virtually nil above 100 kHz. The absolute sensitivity of the microphone (calibrated in water) is approximately 1.2 x 10^{-2} pC/Pa.

Microphones have been installed in the horizontal sections of the three identical char feed lines. The char line is nominal 1 1/4 inch schedule 160 stainless steel pipe, and connections are made with 2-inch Grayloc fittings.[7] The microphone housing is at the center of this section of pipe and consists of a 2-inch tee with a Grayloc hub welded to the branch. The microphone is supported from a mating hub that forms a demountable seal. A 2.22 cm (0.875 inch) hole in the wall of the char line allows the microphone to sense pressure fluctuations in the process stream but causes minimal disturbance to the flow and negligible erosion of the microphone.

Figure 3 shows the microphone as it is supported from the blind Grayloc hub. This support is designed to position the lower edge of the microphone flush with the inner surface of the char line, in the hole that was machined in the pipe wall. The signal lead for the microphone passes through the Conax compression seal[8] as shown. The fitting uses a lava sealant to seal against the high temperature, high pressure gas in the char line.

4.0 DATA

The spectral analysis of the microphone signal is shown in Fig. 4, for various rates of char flow. In each figure, the upper trace is the spectrum of the signal when only steam was flowing in the line. The lower trace is the spectrum taken when char was also flowing. The exact amount of char was not known but the relative flow rate was inferred from valve openings and readings of differential pressure instruments. Figures 4a, 4b and 4c correspond to low, moderate and high relative flow rates, respectively. The lower trace in Fig. 4d shows the spectrum with no char and no steam flowing. All the spectra were taken with an analysis bandwidth of 300 Hz. The reference level at 0 dB corresponds to 1.0 v RMS at the output of the remote charge converter.

The spectrum of the steam-only signal clearly shows that the acoustic signal (noise) from the steam eductor is quite strong and rather uniformly distributed over the frequency range 0 - 50 kHz. As char is added to the line, the microphone signal becomes much smaller, with the greatest decrease at the highest frequencies. The signal is reduced below the level of the analyzer noise for the upper frequencies and its spectrum is not apparent, but it is evident that the signal loss increases with both frequency and char concentration. At the lowest frequencies (below 1 kHz), the signal with char flowing is somewhat higher than the steam-only signal. This is

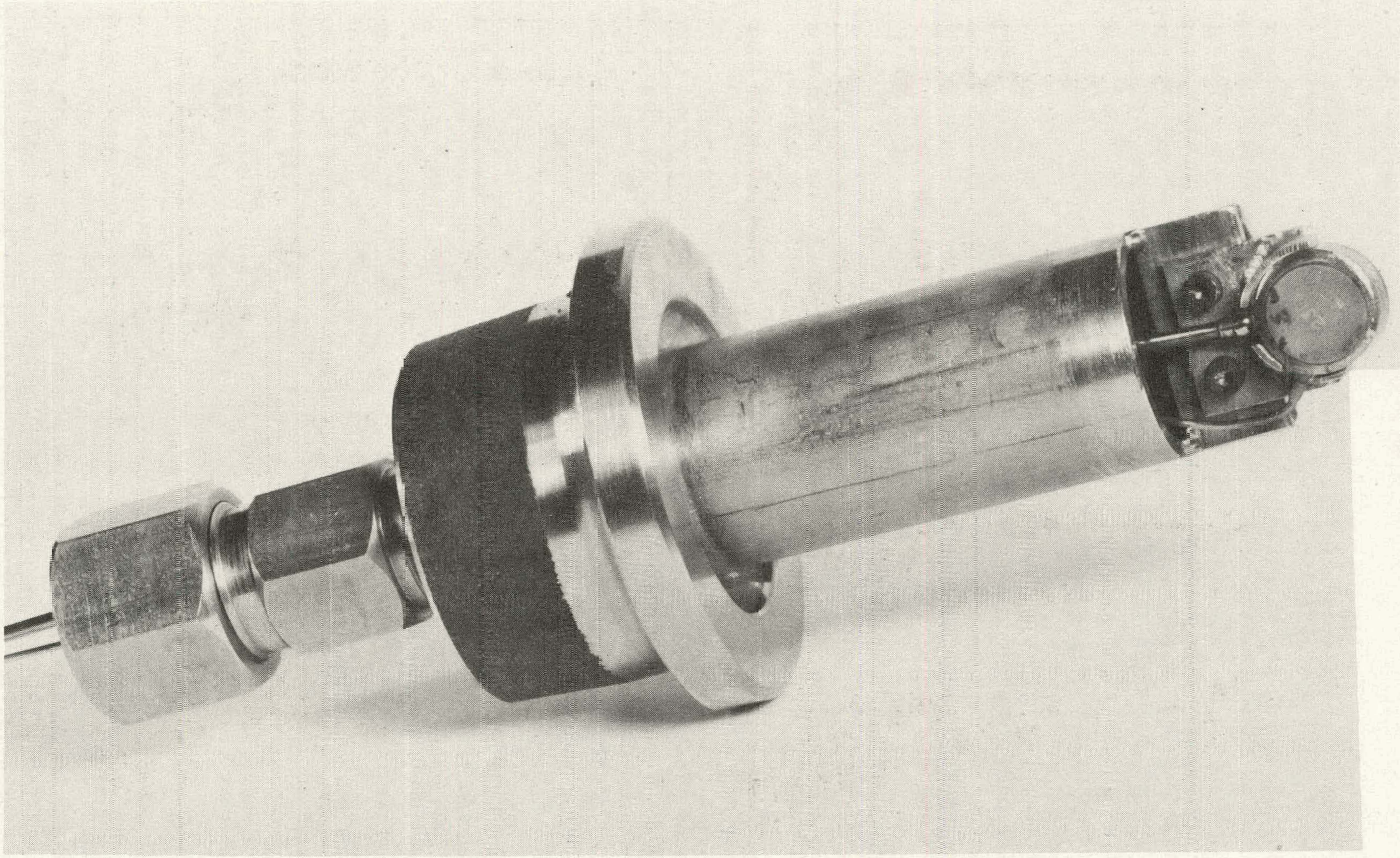


Fig. 3 Photograph of Microphone and Support Assembly

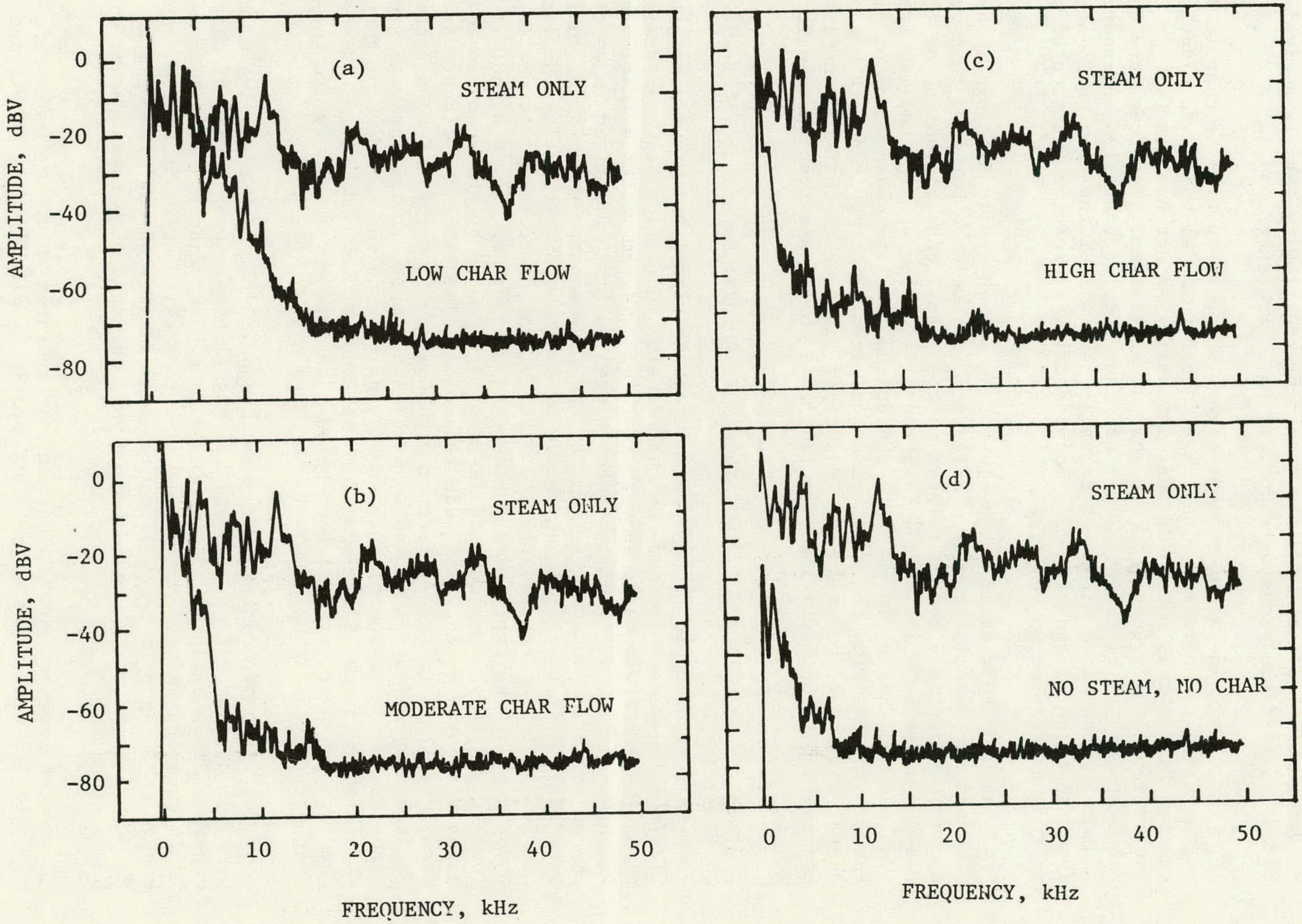


Fig. 4 Spectral Analysis of Microphone Signal

evidence that impingement noise caused by the flowing char is a significant part of the acoustic signal in this frequency band.

The change in the microphone signal which we observe as char is added to the line is consistent with the attenuation model which was discussed in Section 2. In this case, the char is causing an attenuation that is roughly proportional to frequency and to char concentration. The frequency dependence appears to be essentially linear but the concentration dependence cannot be determined without a calibration. All of the data taken so far shows that the attenuation is a monotonically increasing function of the char concentration in the line.

Based on this data, it is clear that we can easily distinguish between flow and no-flow of the char. Moreover, it should be possible to develop a measure that is directly related to the actual char concentration. This measure would be based on the relative attenuation at high and low frequencies and thus would not be dependent on absolute measurement of signal level. For example, the ratio of signal levels in the frequency bands near 1 kHz and 10 kHz will be a monotonic function of char concentration, and could be used (after calibration) as a char concentration (density) meter.

5.0 FLOW MONITOR DESIGN

An instrument to process the microphone signal and provide both the flow/no-flow indication and the char density indication has been designed along the lines discussed above. The block diagram for this instrument is shown in Fig. 5. The microphone signal is first amplified in an external charge amplifier and then is sent to the flow monitor where it is analyzed into three different frequency bands by bandpass filters. The RMS detectors and LOG RATIO converters generate a DC voltage proportional to the log of the ratios of the amplitudes in the frequency bands. The A signal is the lowest frequency component and is least attenuated by the char, so this signal is taken as the amplitude reference. The other two signals are then normalized to this reference with the result being fed to a voltmeter for the intermediate band and to a voltage comparator for the high frequency band. The high frequencies are most sensitive to the presence of char and this signal (signal C) is used for the flow/no-flow indication. Whenever the high frequency signal drops below a certain level relative to the low frequency band, the CHAR FLOW light turns on.

The intermediate frequency band (signal B) is less sensitive to the presence of char but gives a useable signal over a wider range of char density. This band is used to give a continuous indication of char density. It is expected that the signal derived from this intermediate frequency band can be calibrated in terms of actual mass density of char in the pipe. Then if flow velocity can be determined, the mass flow rate of char would be obtained.

Other features which have been incorporated into the flow monitor permit external use of its signals and provide indications of proper operation. Both voltage and current outputs are provided for driving a recorder or a

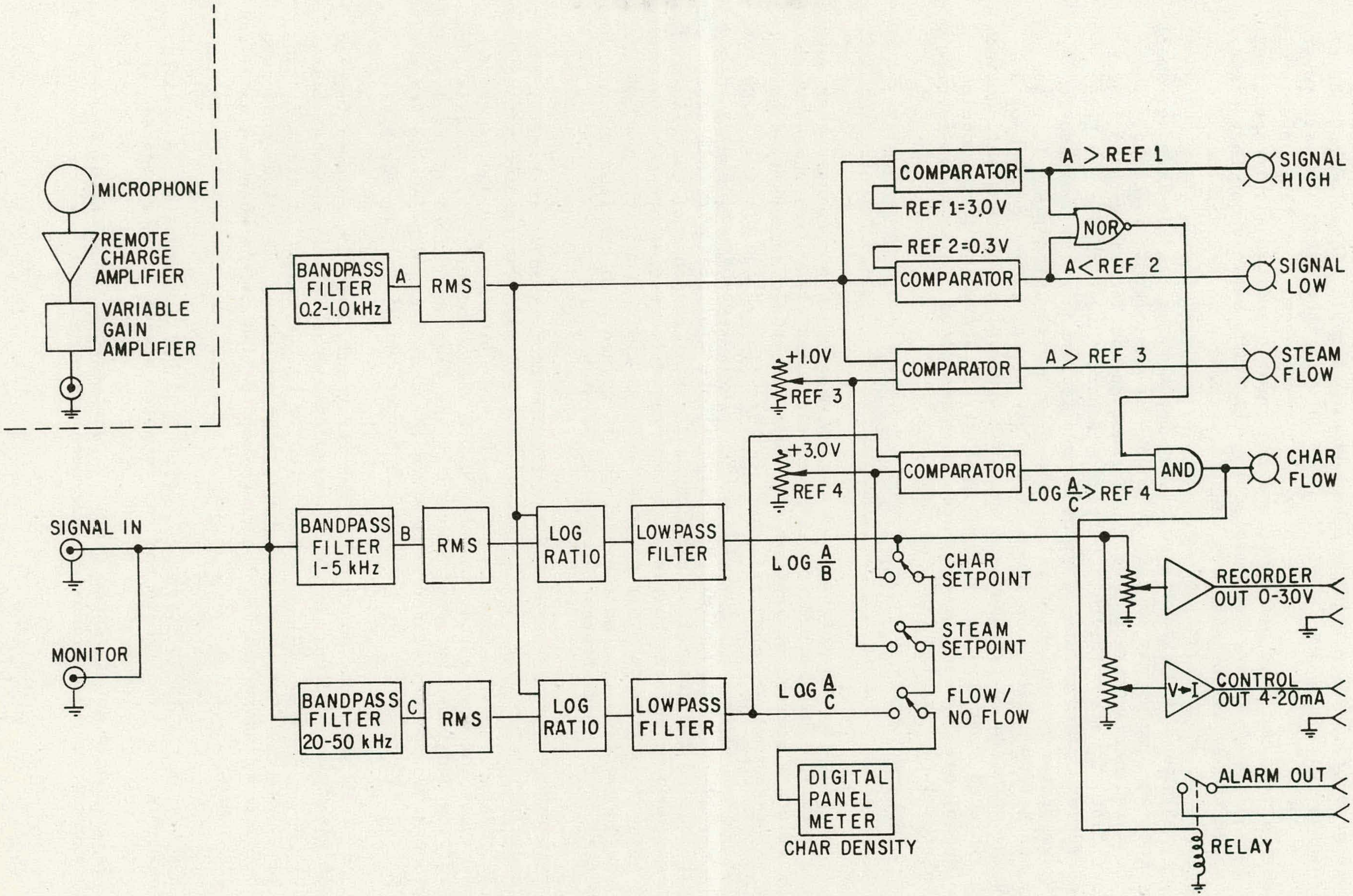


Fig. 5 Block Diagram of Flow Monitor

process control system with the char density signal. These outputs have adjustable gain and time constant. The flow/no-flow signal is used to provide a contact closure for an external alarm system. But the contacts will close only if the unit has power and the input signal is within specified bounds. This guards against misleading CHAR FLOW indications that might be based on signals outside the range of accuracy of the circuit.

Front panel indicators show if the input signal is too large or small and the panel meter may be used to check various circuit voltages. But for comprehensive testing of circuit function, it is necessary to inject known test signals. For this purpose a separate test module has been constructed. This module provides four different signals designed to confirm proper operation of all of the flow monitor circuits. In this way, each flow monitor can be quickly checked out, either as part of a routine maintenance procedure or when the operator suspects a malfunction. The finished Flow Monitor is shown in Fig. 6. Three identical modules are shown, one for each of the three char feed legs. Also shown is the module used for testing the flow monitor.

6.0 RESULTS

The results from the use of the flow monitor at BI-GAS have been quite satisfactory. The instrument has given rapid and clear indications whenever char flow has started or stopped. In addition, the char density signal has responded well to the variations in char flow as the control valve settings have changed. But the flow monitor indication has not always agreed well with other instruments, primarily differential pressure indicators. This may be due to the greater sensitivity and faster response of the flow monitor, but may also be related to the fact that the differential pressure instruments are quite sensitive to other factors, such as gas composition, gas temperature and purge gas flow. As more experience is gained with the flow monitor, it is expected that the discrepancies will be resolved.

An example of the output of the flow monitor is shown in Fig. 7. This is a recording of the char density signal that was made during BI-GAS test G7-A on February 24, 1979. At 2245 hours, the char line plugged and caused a shutdown of the char burner (marked "CLOSE VALVE" on record). At this time, steam flow continued but was diverted by the plug and flowed up the char leg. The operator promptly closed a valve in the char leg, thus forcing steam flow back down along the proper path to the burner and dislodging the plug.

At 2256 hours the char burner was relit and char flow resumed (marked "OPEN VALVE" on record). It is observed that char flow is somewhat less stable at this time. This is speculated to be the result of steam flowing up the char leg for a short time during the shutdown. The steam condensed on the char, causing the char to clump and to flow poorly when the valve was opened again.

The sensitivity and speed of response of the flow monitor is clearly seen in Fig. 7. Even though the char density signal is uncalibrated, it provides valuable information to the plant operator. Stability of the flow is easily judged and the char density signal allows the operator to know when a previously used flow rate has been achieved.

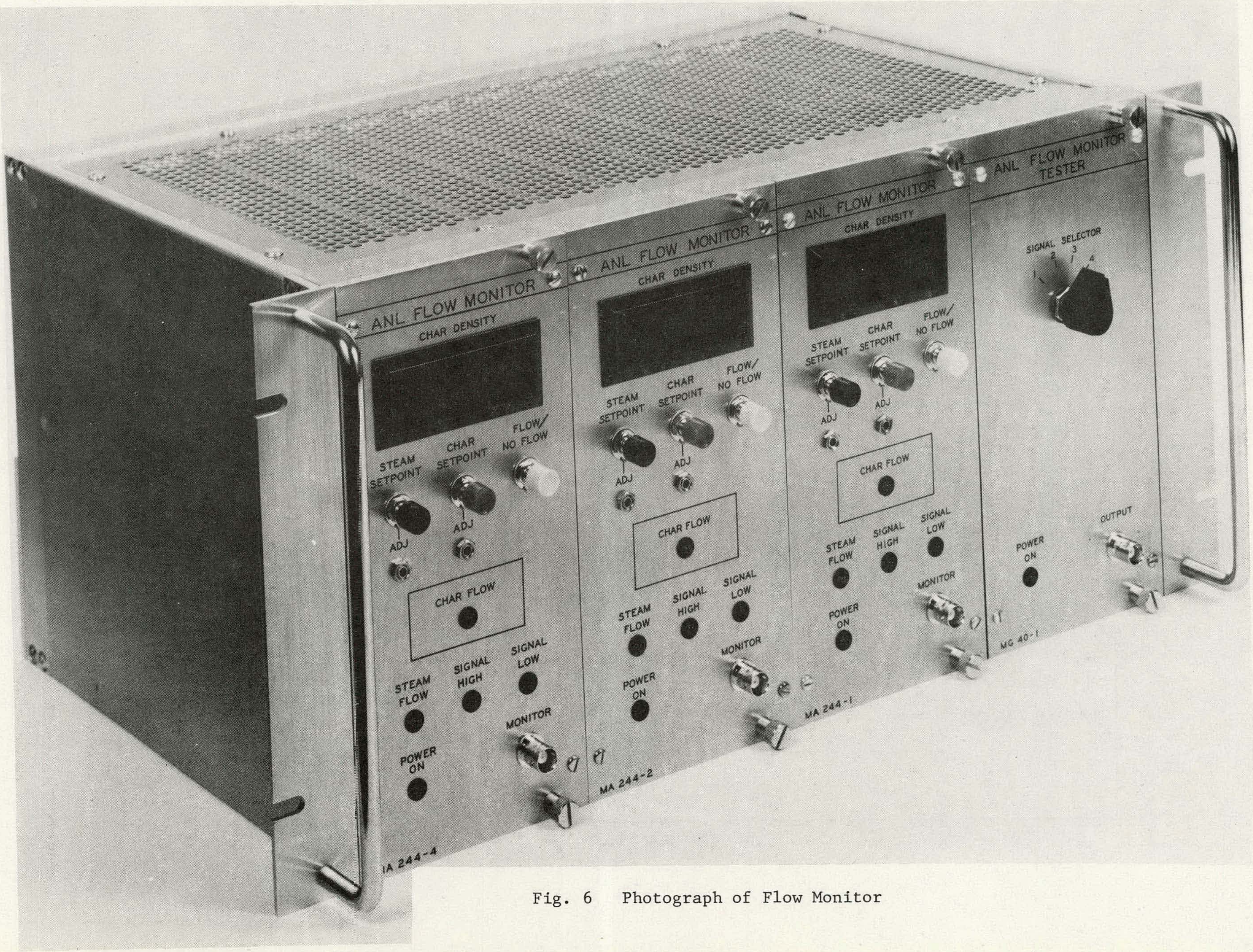


Fig. 6 Photograph of Flow Monitor

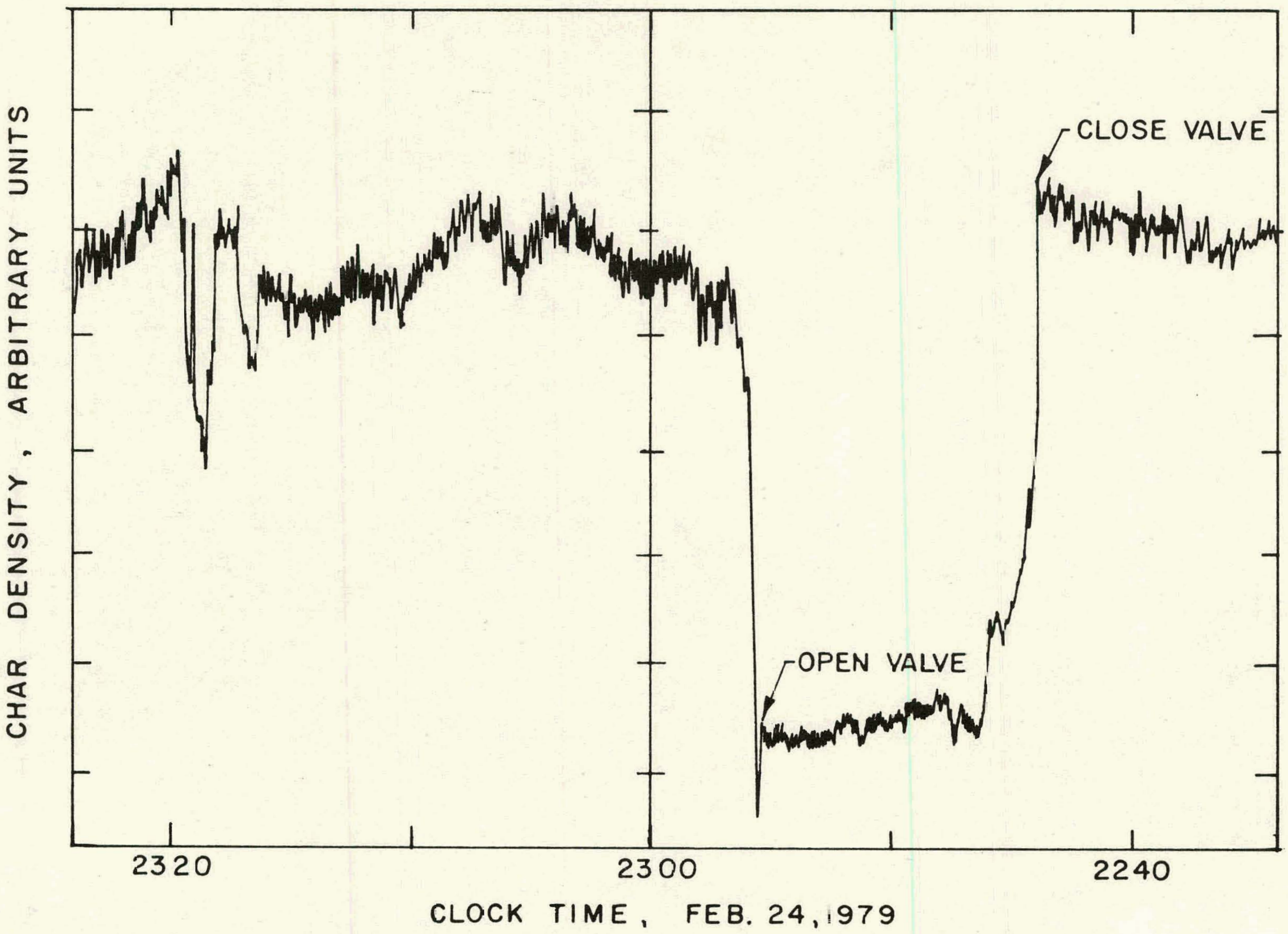


Fig. 7 Recording of Char Density Signal

Experience with the acoustic flow monitor has been sufficiently encouraging that BI-GAS is considering using the device to control oxygen feed to the lower stage of the gasifier. If this can be done reliably, the supplemental fuel gas feed to this stage can be eliminated, thereby achieving a major milestone for the plant. In the past, the fuel gas has been added to prevent a dangerous oxygen-rich condition from occurring in case of an undetected loss of char feed. But if oxygen flow can be closely matched to char flow, then the fuel gas is no longer needed. The acoustic flow monitor is currently the most promising device for providing the necessary char flow signal.

7.0 FUTURE PLANS

Application of the acoustic flow monitor to the two coal feed lines to the BI-GAS gasifier is being considered. The coal lines are a different size from the char lines and the acoustic properties of the particles and the carrier gas are somewhat different. But the acoustic technique is still valid and is expected to work well in this application.

Since no calibration has been performed on the char density signal, it is only an indication of relative char density or flow. This is adequate for maintaining steady flow or for establishing a previously used flow. But calibration will permit optimization of the gasifier operation by allowing an accurate balance to be made between steam, oxygen and char flow rates. It is for this reason that plans are being made to calibrate the device under actual plant operating conditions.

The first step will be the calibration of the gamma-ray level monitor in the char feed vessel. Since this device is sensitive to gas temperature, pressure and composition, it is important that this step be performed at operating conditions. Once this has been done, the calibration of the flow monitor is obtained by noting the readout indication under conditions of steady char flow in the leg being monitored. The actual flow rate is obtained by measuring the rate at which the level drops in the char vessel. This assumes that char flow into the char vessel has been diverted for the period of the measurement. By repeating the measurement under different flow conditions, a full range calibration will be obtained.

Such a calibration is necessarily dependent on the char velocity during the measurement. If this velocity is essentially constant, then there is a fixed relation between char density, as measured by the flow monitor, and the mass flow rate used in the calibration. But if char velocity tends to vary, then it is important that this velocity be known. For this reason, an acoustic velocimeter may also be necessary in the char lines. This device would use passive cross-correlation[9] of the signals from two microphones to give char velocity. In essence, this technique measures the transit time for flow eddies to travel betwen the microphone locations. Since the separation of the microphones is known, the flow velocity can be directly calculated. When combined with the char density measurement, this gives mass flow rate of the char, even when the velocity is changing. This instrumentation would give the most reliable measure of char flow.

8.0 CONCLUSIONS

The char feed lines at the BI-GAS Pilot Plant represent a situation in which passive acoustic listening is especially well suited for char flow monitoring. The presence in each line of a strong acoustic source (the steam eductor) allows a measurement to be made of the acoustic attenuation caused by the char. A high temperature microphone in the line and a relatively simple signal processor give rapid, sensitive indications of char density.

Although the original goal of providing a flow/no-flow monitor has been achieved, it is now apparent that the same instrument can almost certainly be used as a char density meter. For this, only a calibration is needed, since the device now provides an output signal that varies with char density over a wide range. If the char velocity is also known, the actual char flow rate can be calculated.

Auxiliary features of the flow monitor permit checking its operation and checking the input signal for proper amplitude. In addition, outputs are provided which can be used for making permanent records of the char density or for performing alarm or process control operations. As more operating experience is gained with the flow monitor, the device will likely undergo further changes to make it more reliable, more convenient and more useful in assisting the operation of BI-GAS.

9.0 ACKNOWLEDGEMENTS

The authors would like to thank T. K. Lau of DOE and G. S. Rosenberg, T. P. Mulcahey, and N. M. O'Fallon of ANL for their support and encouragement in this work. We would also like to thank the BI-GAS personnel, especially Dennis Kelly and Bill Miller of Stearns-Roger, Inc., for their help and cooperation. And special thanks are due to Howard Eisenbrandt for preparation of drawings, Martin Miskevics for help with the microphones and Nancy Heeg and Brenda Love for the typing of this report.

10.0 REFERENCES

1. A. L. Wilson, Safety Assurance Study of High BTU Coal Gasification Pilot Plants - Interim Report, ERDA Report No. FE-2240-8 (Aug 1976)

2. N. M. O'Fallon, R. A. Beyerlein, W. W. Managan, H. B. Karplus, and T. P. Mulcahey, A Study of the State-of-the-Art of Instrumentation for Process Control and Safety in Large-Scale Coal Gasification, Liquefaction, and Fluidized-Bed Combustion Systems, Argonne National Laboratory Report No. ANL-76-4 (Jan 1976)

3. P. D. Roach and A. C. Raptis, A Preliminary Report on the Flow No-Flow Indicator for the BI-GAS Char Line, Argonne National Laboratory Technical Memorandum No. ANL-FE-49622-TM02 (July 1978)

4. J. W. Zink and L. P. Delsasso, Attenuation and Dispersion of Sound by Solid Particles Suspended in a Gas, J. Acoust. Soc. Am. 30(8), 765-771 (Aug 1958)

5. L. D. Mullins, W. F. Baldwin, and P. M. Berry, How Detectors Measure Flowline Sand, Oil and Gas Journal, Feb 3, 1975, p. 101

6. A. P. Gavin, T. T. Anderson, and J. J. Janicek, Sodium Immersible High-Temperature Microphone - Design Description, Argonne National Laboratory Technical Memorandum No. ANL-CT-75-30 (Feb 1975)

7. Gray Tool Co.., Houston, TX

8. Conax Corp., Buffalo, NY

9. J. Coulthard, The Principle of Ultrasonic Cross-Correlation Flow metering, Meas. and Control,Vol. 8, 65-70 (Dec 1973)

STATUS OF THE EVALUATION OF A CORIOLIS EFFECT MASS FLOW METER FOR DENSE PHASE COAL FLOWS

W. E. Baucum
The Energy Conversion Division
The University of Tennessee Space Institute

1. INTRODUCTION

1.1 Statement of Problem

In large scale coal conversion and combustion systems, process control requires a continuous monitoring of the mass flow of the coal in its carrier gas or liquid substance. This mass flow measurement represents a key parameter of coal systems including coal fired Magnetohydrodynamic (MHD) energy conversion research. A number of techniques have been considered for implementing the measurement of multi-phase flows. In situations where instantaneous changes in flow are not critical, load cells can be used to determine a weight change which, considered with the corresponding time increment, provides a measurement of the average mass flow during that period. Volumeric methods are also widely used to measure these flows. Other techniques rely on ultrasonic Dopler shift, optical density measurements, gamma-ray absorption, density measurement, capacitance measurements, and techniques which rely on correlation.[1]

Recently a new type of mass flow meter became commercially available which showed promise for applicability to the coal flow measurements. This mass flow meter uses the coriolis force generated by the flow of a substance to measure the mass which generates the force.[2,3] This device has successfully measured the flow of high viscosity fluids in solid-liquid mixtures. Such measurements were found to be independent of such typical parameters as temperature and pressure of the flowing medium. This device is also capable of measuring the approximate density of the flowing medium.

Coal flow rates have previously been measured at The University of Tennessee Space Institute (UTSI) R&D Facility through the use of load cells which measure the change in weight of the coal hopper. This method is generally unsatisfactory. The change in weight of the coal hopper for the time intervals for which the flow indication is desired is small in comparison to the total weight of the hopper. Also, the output signal from the load cells contains extraneous noise from several sources. These two problems combined cause the calculation of coal flow to be incorrect unless the load cell output is averaged over a long period of time, on the order of tens of seconds.

An evaluation of the specifications of the coriolis effect mass flow meter indicated it was amenable to providing a continuous measurement of coal mass flow. The device was therefore purchased and plans formulated for its evaluation. The first step of the evaluation involved installating the coriolis meter in the coal feed system to determine if there were any major problems.

The initial evaluation is discussed in section 3.1. Following this evaluation the mass flow meter was used in actual MHD power tests to determine its performance and compare its measurements to those obtained using the load cell (over the longer period of time) to determine a rough calibration with coal flow; this is discussed in section 3.2. The last step in the evaluation was to execute a series of more accurate calibration experiments to evaluate the meter's performance over a wide range of flow conditions as is discussed in section 3.3.

2. FACILITY DESCRIPTION

2.1 Coal Flow System

The coal flow system used at the R&D facility at UTSI, as shown in Figure 1 and a photograph in Figure 2, delivers a mass flow of 0.3 to 1.1 lb/sec to the combustion chamber. The system has two coal hoppers each of whose capacity is approximately 2000 pounds. When the hopper is pressurized up to about 100 psig, coal is forced by the pressure difference through 3/4" OD stainless steel tubing (0.65" I.D) to the combustor located some distance away. After the coal leaves the hopper, transport nitrogen is introduced into the tubing at a pressure of approximately 15 psig above the hopper pressure to initiate the flow of the coal to the combustor (see Figure 1). When first installed, the mass flow meter was mounted at the base of the hopper in the coal line, at a position just downstream of where the transport gas was introduced. In later tests its position relative to the transport gas entrance was changed. In order to evaluate the effect of flow "slugging" and its absence, the meter was also located upstream of the introduction of the transport gas.

2.2 Mass Flow Meter

The coriolis mass flow meter as purchased from Micro-Motion Inc. of Boulder, Colorado has an analog output and operates in a flow range of 0 to 1.5 lb/sec. It is shown in Figure 3 as it is presently mounted to welded I-beams. The operation principle of the measurement relies on the coriolis force generated by mass flowing in a vibrating U-shaped tube. The tube, excited for vibration at its natural frequency, precesses about an axis perpendicular to its vibrational axis due to the influence of the coriolis force. The angle of precession is measured optically and is related to the mass flow through the tube.[2,3] The tube is sized for a particular flow range so as to obtain as high a density of the flowing medium as possible with a minimum pressure drop. The tube size in this unit is ½" I. D. The density of the flowing medium can also be determined by measuring the vibration frequency through its relationship to the elastic constants of the tube

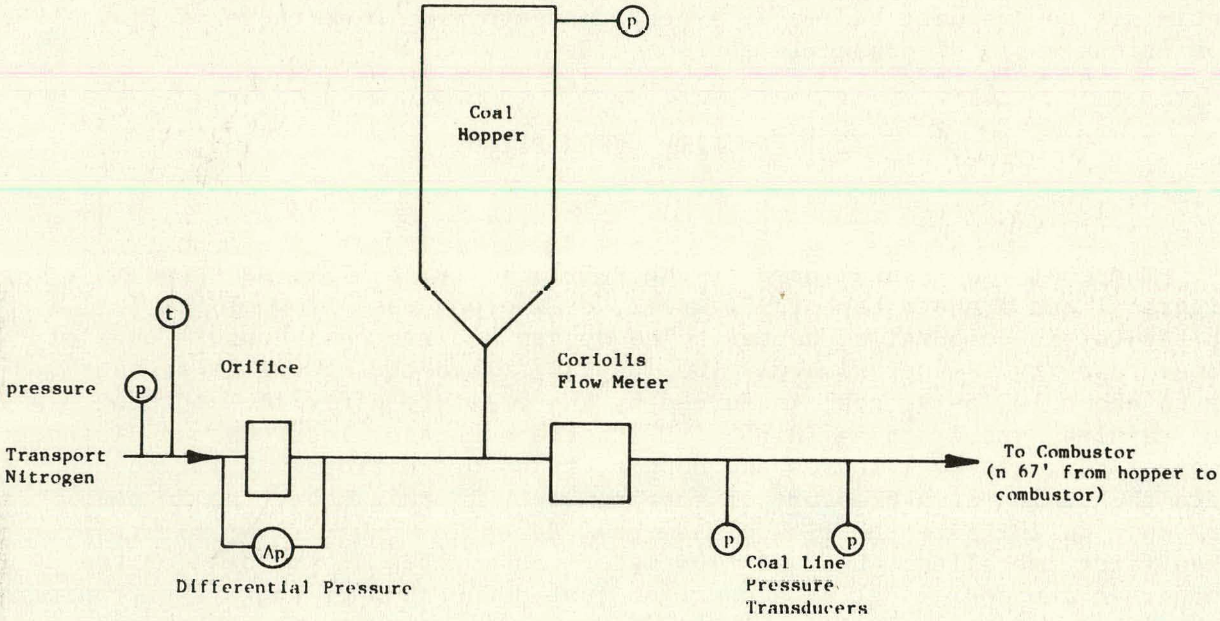


Figure 1. Coal System Schematic

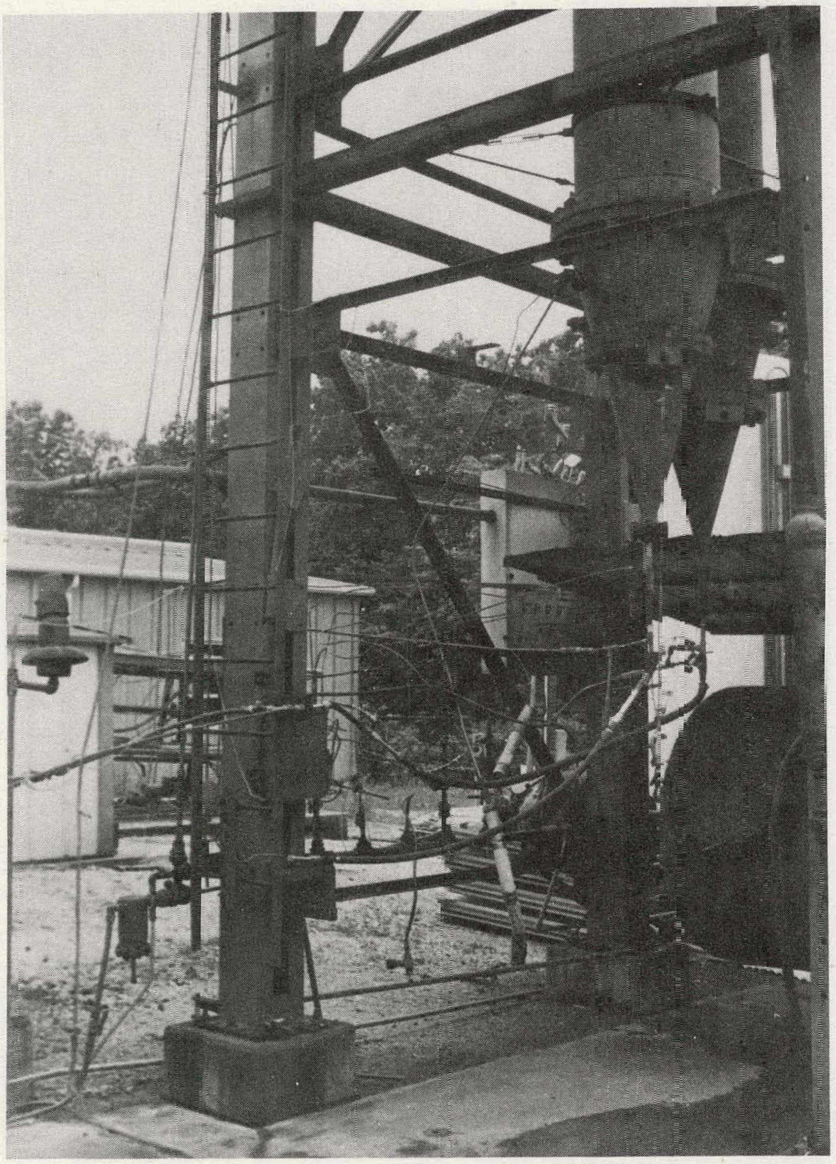


Figure 2. Coal Delivery System

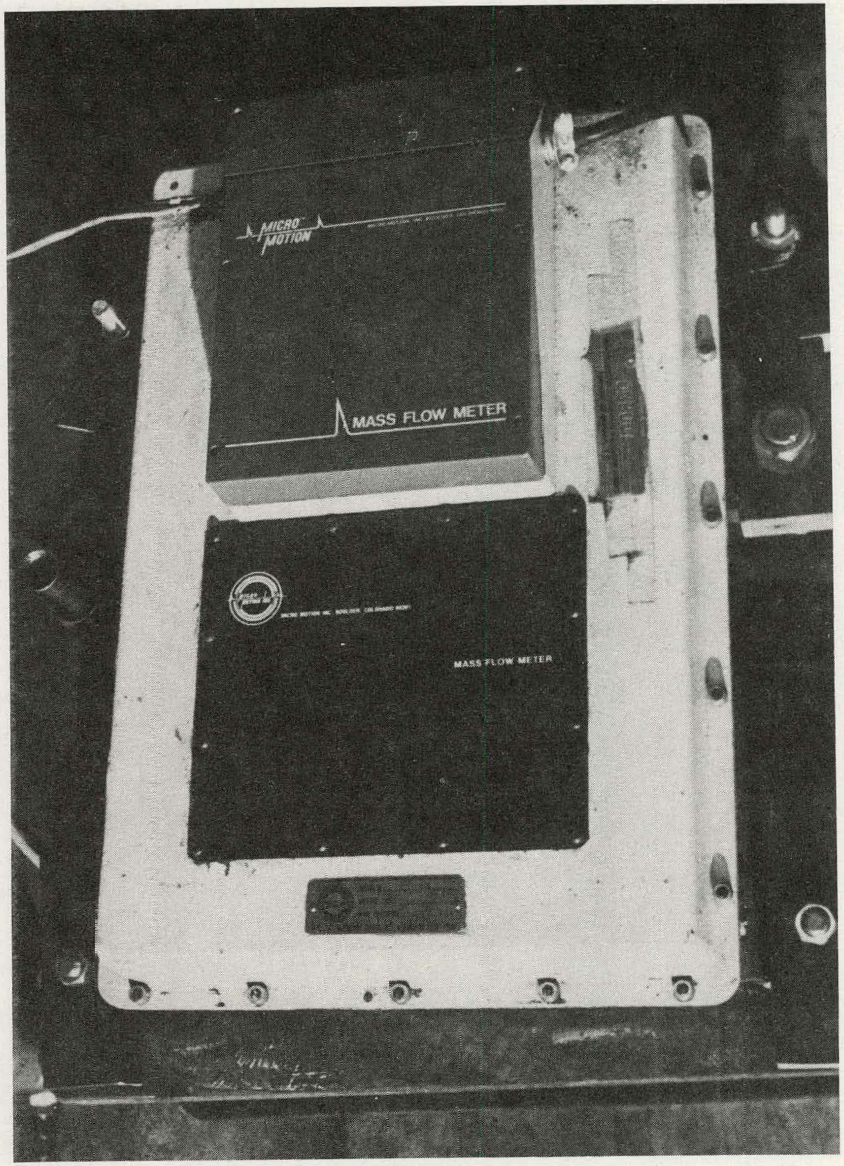


Figure 3. Coriolis Mass Flow Meter

and the density of the flowing medium.[2,3] This measurement is somewhat approximate, however, due to the dependence of the natural frequency on temperature. A square wave output voltage separate from the flow rate output signal is supplied to facilitate the density measurement.

2.3 Instrumentation and Data System

All experimental data was collected using a digital data acquisition system which consists of signal conditioning amplifiers, signal multiplexer, analog to digital converter and a Data General Eclipse S/230 computer. Scan rates of one hertz and ten hertz were utilized during the experiments. Data taken during the experiments were stored on magnetic tape for later analysis.

During the facility coal flow experiments, the following data parameters were recorded using the digital data acquisition system: Mass flow and density from the coriolis mass flow meter, coal line pressure, coal hopper pressure, differential pressure, absolute pressure and temperature of transport gas at an orifice for calculation of the flow rate of transport gas, coal hopper weight, and position of valves in the coal delivery system.

In addition, the signals from the flow meter and the coal line pressure transducers were recorded on magnetic tape by a Honeywell Model 5600 tape recorder over a frequency range of 0 to 5000 Hz.

3. TEST RESULTS

3.1 Initial Experiments

Before attempting to measure any coal flow rates, the mass flow meter was first calibrated using water as a flowing medium for flow rates ranging from 0.17 to 1.25 pounds per second. A linear response was confirmed. A lease-square curve fit to the data points resulted in the following calibration equation:

$$F = 0.01 + 0.30\ V$$

where F is mass flow rate in pounds per second and V is the flow meter output voltage.

It was then decided to perform an experiment to determine the meter's response to coal flow. For this experiment, it was desirable to set up several stable coal flow rates through the meter. This was found to be somewhat difficult since this experiment was to be separate from the normal MHD tests in which the coal is exhausted in a combustor at a pressure of 4 atmospheres. In this case, the coal was exhausted into a large barrel at atmospheric pressure and thus, the normal plant operating parameters could not be used. Instead, considerable experimentation with the operating parameters was required.

During this experiment the meter was mounted on a vertical stand beneath the coal hopper and was connected in the coal line just downstream of the point where the transport gas and coal were mixed.

Table I shows the various parameter values that were tried and the resulting meter behavior. It should be noted that considerable vibration in the coal line was evident through this experiment, indicating that there were probable instabilities or "slugging" in the coal flow. No coal line plugging was observed during any part of the experiment. Table I shows that the flow meter appeared to follow the flow only during the early phase of the experiment. The results are somewhat inconclusive, however, since it is doubtful any stable flows were obtained.

Table I. Parameter Values Used in Initial Coal Flow Experiment

Hopper Pressure (PSIG)	Hopper Valve Setting (% open)	Transport Gas Pressure (PSIG)	Behavior of mass flow meter
110	50	125	indicated flow beginning at 0.7 lb/sec and increasing to 3 lb/sec at flow termination
65	100	75	erratic (0-1.5 lb/sec)
30	28	40	full scale reading

The flow meter was left in position and used during an MHD power generation experiment, but its readings varied randomly from 0 to 1.5 pounds per second while the average flow as calculated from the hopper weight was about 1 pound per second. Again, considerable vibration of the coal line was noticed, indicating the coal was slugging through the line.

Another experiment was performed which was similar to the first one in which that the coal flow was initiated from the hopper through the flow meter into a drum; however, in this case during the latter part of this second experiment, the flow meter was connected upstream of the transport nitrogen. The purpose of this experiment was to compare the behavior of the flow meter for the more stable coal flow which existed upstream of the transport gas to the less stable flow downstream. During the first part of the experiment when the flow meter was downstream of the transport nitrogen it behaved erratically. During the latter part of the experiment when it was upstream of the transport nitrogen, it behaved properly and agreed well with the load cell calculated flow when averaged over a period of about 7 seconds.

Following these tests, the manufacturer was consulted as to why the flow meter would operate properly upstream of the transport nitrogen but not downstream. The following possibility was offered.

The tubing inside the flow meter through which the coal flows is caused to oscillate by a drive coil and it is possible that if the coal were not uniformly distributed in a transport gas but was "slugging" through the tube, it could rob energy from the oscillation and cause the flow meter to cease functioning. This could only happen when the flow meter was downstream of the transport gas where the coal might become non-uniformly distributed in the mixture. The manufacturer mentioned that others had experienced the same problem with fluid flows if the bubble content became too large. He further suggested a means by which we could monitor the oscillation of the tube during operation to see if this was the source of the problem. This oscillation was monitored during several subsequent tests and it was found that the oscillation was indeed damped out at those times when the flow meter ceased to function properly, apparently caused by the coal particles being non-uniformly distributed in the transport gas. Thus, for those tests previously discussed where the meter did not function properly, the probable cause was the slugging coal flow obtained.

3.2 Initial Calibration Experiments

In order to obtain an initial calibration the flow meter was used during two MHD power generation experiments connected upstream of the transport nitrogen and performed very well during both tests. A comparison of the coal flow rate calculated from the load cell data averaged over 7 seconds and the voltage output of the mass flow meter showed a proportionality constant of 0.285 with a standard deviation of 0.005 for one experiment and a value of 0.283 with standard deviation of 0.003 for the other experiment. This also agreed well with the proportionality constant of 0.3 obtained during the water flow calibration.

Following these experiments, some problems were experienced with the flow meter. These problems appeared to arise from several different sources; first, a drift in the zero value occurred which was caused by a sensitivity to vibration and a lack of sufficient rigidity in the mount. Second, moistured collected inside the case causing corrosion of the circuit board. After cleaning the circuit board as well as possible, we decided to mount it on a very stable platform in the test bay area to prevent the zero drift and to protect it from the weather. Upon adjustment according to factory recommendations, the flow meter functioned well when water was the flowing medium but did not function at all when coal was the medium. Finally, after making some adjustments which were contrary to factory recommendations, the flow meter was made to function (upstream of the transport gas) with the coal medium but it then would not function with water as the medium.

In this condition the flow meter was used in four MHD power generation tests to further determine its behavior under test conditions. It appeared to function properly during all these tests and some visual correlations could be made among the coal line pressure, plasma luminosity, exhaust gas temperature and the flow meter data. For the first three power generation experiments a comparison was made between the load cell data and the flow meter data for the total indicated mass flow during the entire tests. To obtain the total mass flow from the load cell data the average load cell reading after the test was subtracted from the average reading before the test since there were no vibrational errors in the load cell readings before and after the test as there was during the test. To obtain the same quantity from the flow meter data, the output voltage was integrated using Simpson's rule from beginning to end of the test, and this value was substituted for V in the calibration equation. In this manner, good agreement was obtained between the load cell data and the flow meter data.

Since the mass flow meter would not operate properly for both water and coal and required adjustment contrary to factory specifications to operate with coal it was decided to return the unit to the manufacturer, who had agreed to install new circuit boards to replace the corroded ones, before beginning the next phase of the coal flow calibration experiment. When the unit was returned to us by the manufacturer it was recalibrated using water as the flowing medium and found to operate properly.

3.3 Final Coal Flow Calibration Experiment

Up to this point the mass flow meter had been calibrated using only water as the flowing medium and measurements made with coal flow could be calibrated only using the load cell data which contained some error. Thus it was decided to attempt a more accurate calibration experiment with coal as the flowing medium.

The experimental system used for this calibration experiment is shown in Figure 4. In this system the coal flows from the coal hopper into the 3/4" OD tubing where the transport gas is mixed with coal. The mixture flows through the mass flow meter and coal line pressure transducers, through a variable ball valve which is used in conjunction with the coal hopper pressure to control the flow rate, and to a tee joint which is controlled by two valves that allows the coal to flow into the large drum or into a smaller barrel which is sitting on a scale to measure the change in weight. In order to determine the true mixture ratio for the coal and transport nitrogen gas, the flow of nitrogen to the hopper and to the transport line was measured. A flow meter connected in the coal hopper pressurization line measured the flow of the nitrogen into the coal hopper and a calibrated orifice was placed in the transport gas line for the measurement of flow from this point. The experimental plan called for the establishment of a steady coal flow at some predetermined flow rate into the large drum. When this flow was established, the valves at the tee were operated to divert the flow of coal into the barrel for a period of two minutes. The average coal flow during the two minute period was calculated from the change in weight of the barrel. Comparison with the signal from the mass flow meter provides the calibration. To ensure that the flow was in the dense phase regime where optimum performance of the mass flow meter had previously been observed, no transport gas was used during this part of the experiment. During the second part of the experiment, a range of flow rates for the transport gas was established for the purpose of varying the coal to nitrogen mixture ratio. Several ratios were included from 250:1 to a value of about 50:1 by mass to test the performance of the meter in the lighter phase flow regimes.

Thus, in the first part of the experiment, coal mass flows of 1.34, 0.78 and 0.45 pounds per second were each set up and valved into the barrel for two minute periods. The average mass flow meter output voltages calculated for these periods of time are shown in Figure 5. The plot obtained was very linear and a least-square curve fit to these point gave the equation:

$$F = 0.346\ V - 0.1$$

where F is the flow rate in pounds per second and V is the output voltage of the mass flow meter.

The correlation factor of the curve fit was 0.99 and the estimated variance in calculated value was 0.135 volts^2. Also it was found that a linear relationship existed with the differential pressure between the coal hopper and the pressure transducer (located in the coal line just downstream of the mass flow meter) and the average mass flow rate as shown in Figure 6. This indicated that the density of the flowing medium was quite constant during the experiment and suggested that for this particular case where the density of the flow is constant a pressure differential measurement could be used to measure the mass flow rate. Figure 7 shows time plots of the mass flow meter output voltage for the three flow rates. The variation in oscillation frequency of the vibrating tube for the three flow rates also indicated that the density of the flowing medium during these three flows was very constant. Measurements of the flow of pressurizing nitrogen into the coal hopper indicated that the flow was just sufficient to displace the coal flowing out of the hopper and therefore the amount of pressurizing nitrogen which flowed out of the hopper with the coal must be negligible so that the three coal flows obtained were in the very highly dense phase regime. All of the information shown here indicated that the mass flow meter operated very well in this regime and the calibration curve obtained was very linear.

In the second part of the experiment the same experimental system was used except, in this case, transport nitrogen gas was used to vary the coal to nitrogen mixture ratio. Figure 8 shows some results of this part of the experiment. This is a time plot of the mass flow meter output voltage over a time period where four different mixture ratios were obtained as indicated on the figure. In addition, figure 9 shows the time plot of the mass flow meter output voltage for a fifth mixture ratio of 49:1. It is evident from these two figures that the output voltage from the meter, which was quite stable for flows without transport gas shows greater fluctuations as the coal to nitrogen ratio decreases. In fact the output voltage fluctuations becomes excessive at mixture ratios less that 128:1. At one point during this experiment the mass flow meter output voltage showed a very uniform fluctuation frequency as indicated in the top part of Figure 10; the pressure fluctuations in the coal line at the same period of time are shown in the middle part of this figure and can be seen to correlate very well with the fluctuations of the output voltage of the mass flow meter.

This same correlation can be seen at other time periods also, where there were fluctuations in the flow meter output voltage. A time plot of the density signal from the mass flow meter shown in the lower part of figure 10 indicates fluctuations in the density of a flowing medium which

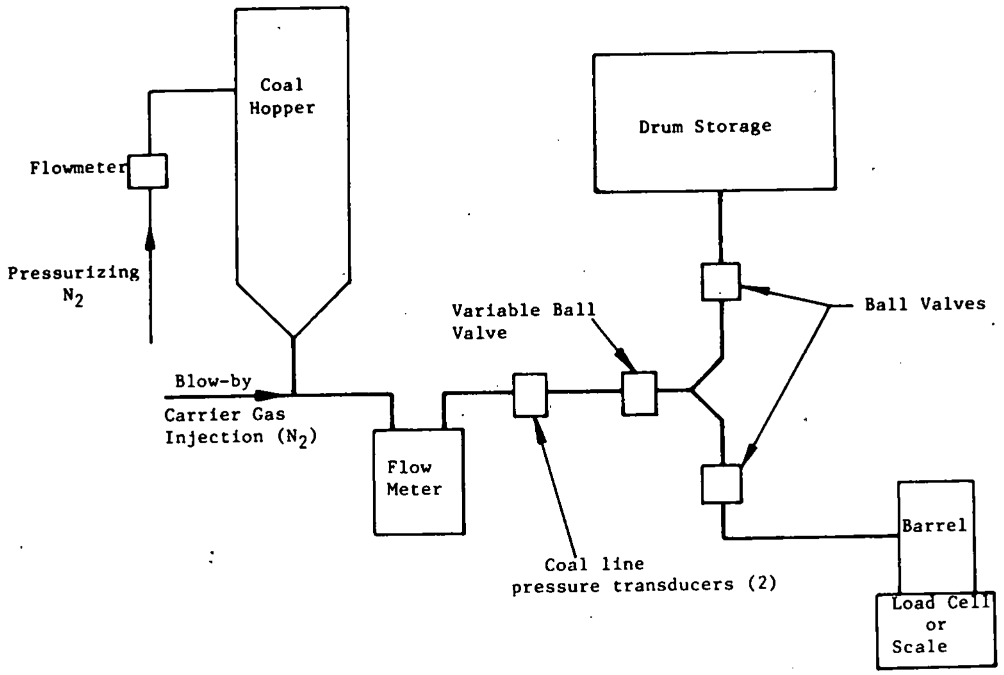


Figure 4. Mass Flow Meter Test System

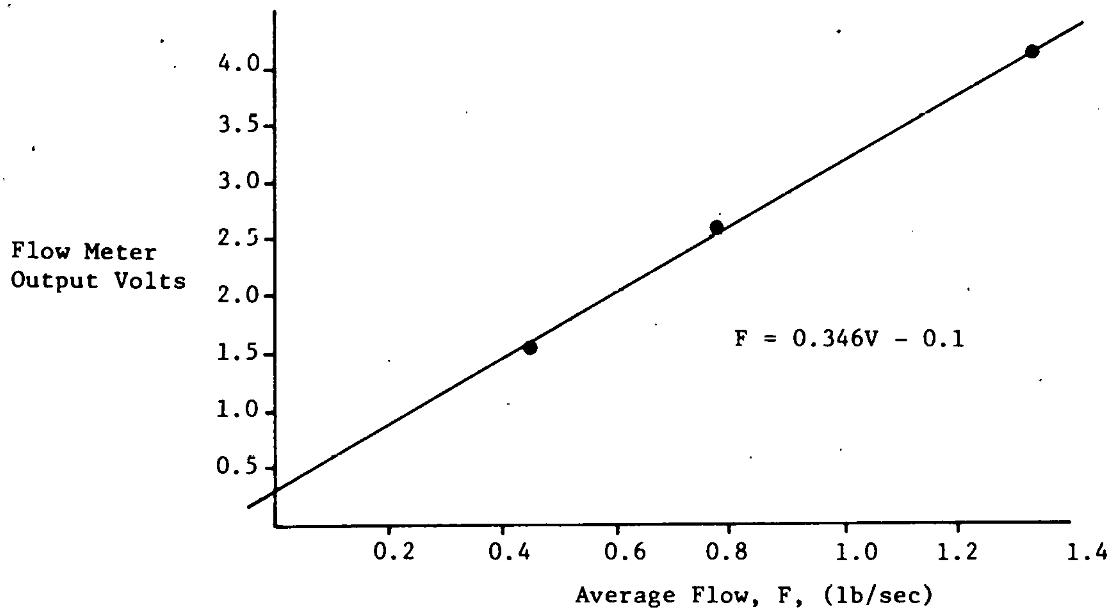


Figure 5. Results of Mass Flow Meter Calibration

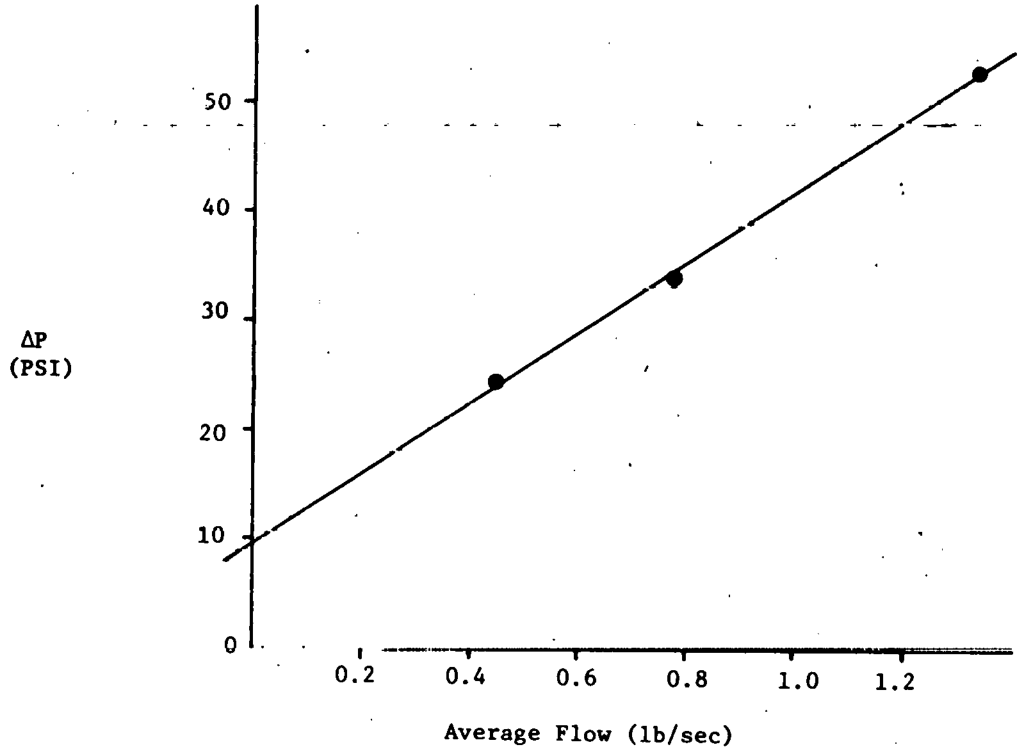


Figure 6. Pressure Differential Vs. Flow Rate

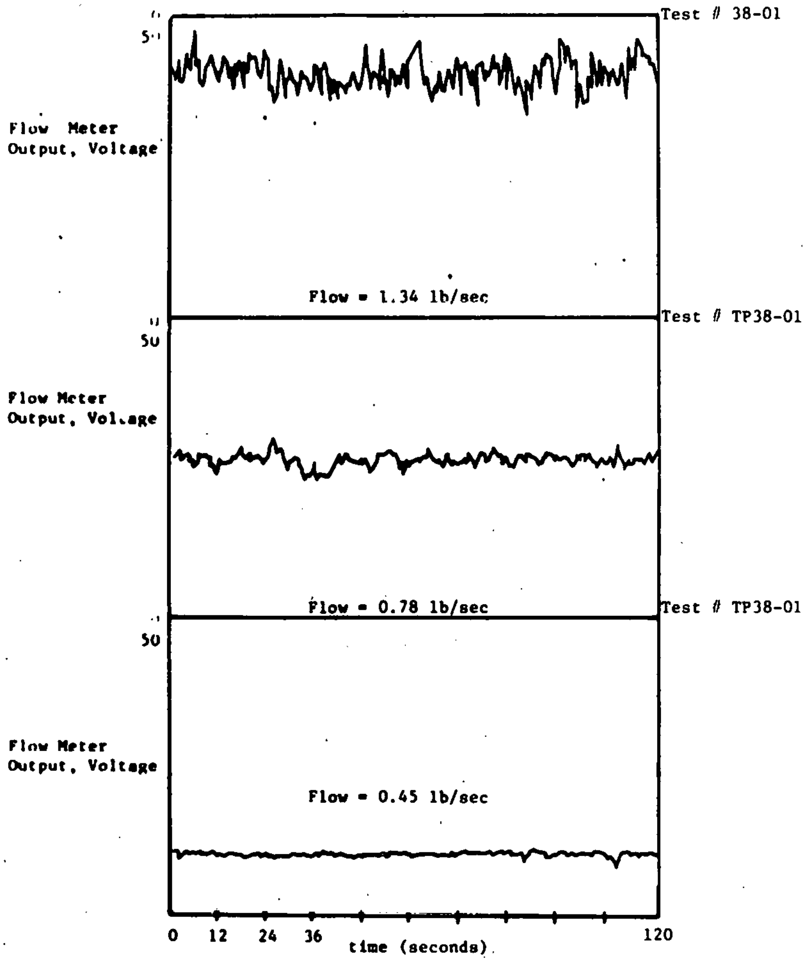


Figure 7. Mass Flow Meter Response During Calibration Tests

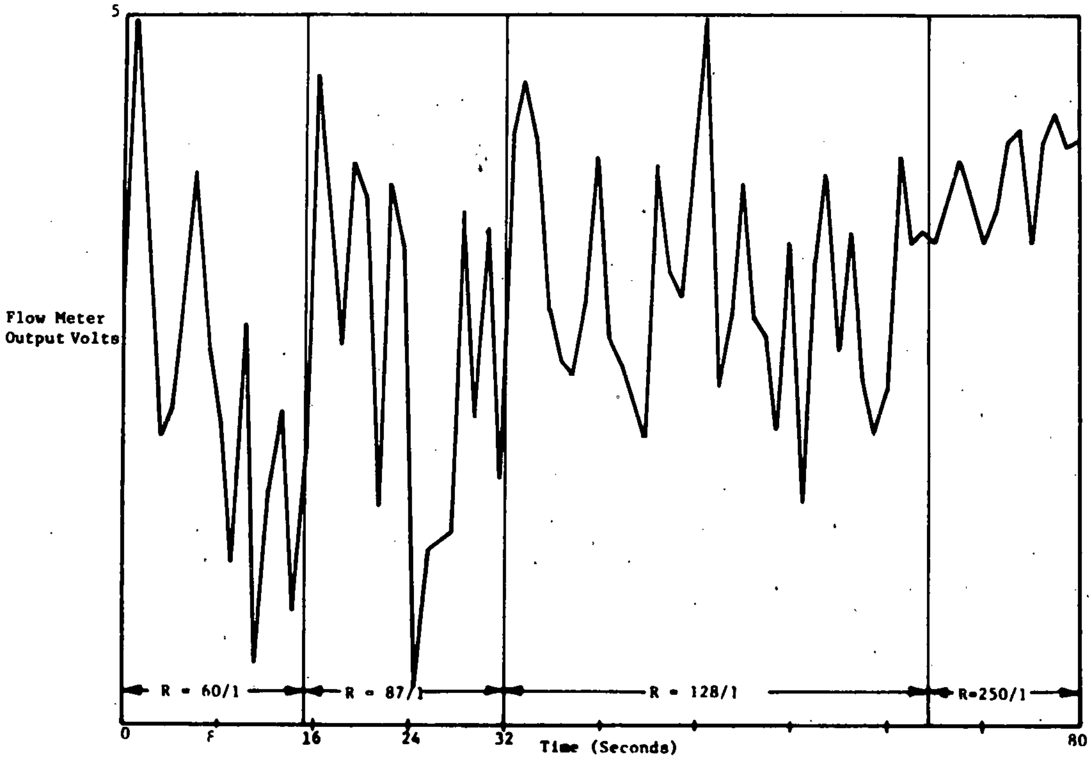


Figure 8. Flow Meter Output as a function of Different Mixture Ratios, R

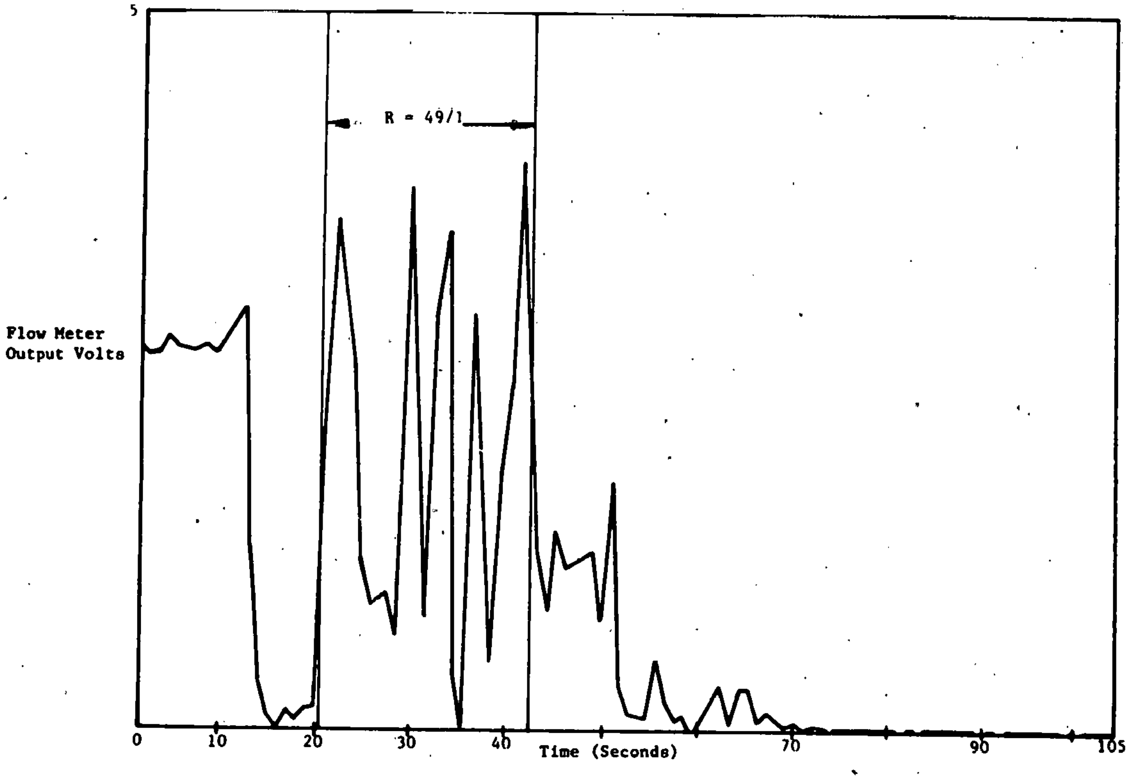


Figure 9. Flow Meter Output for 49/1 Mixture Ratio, R

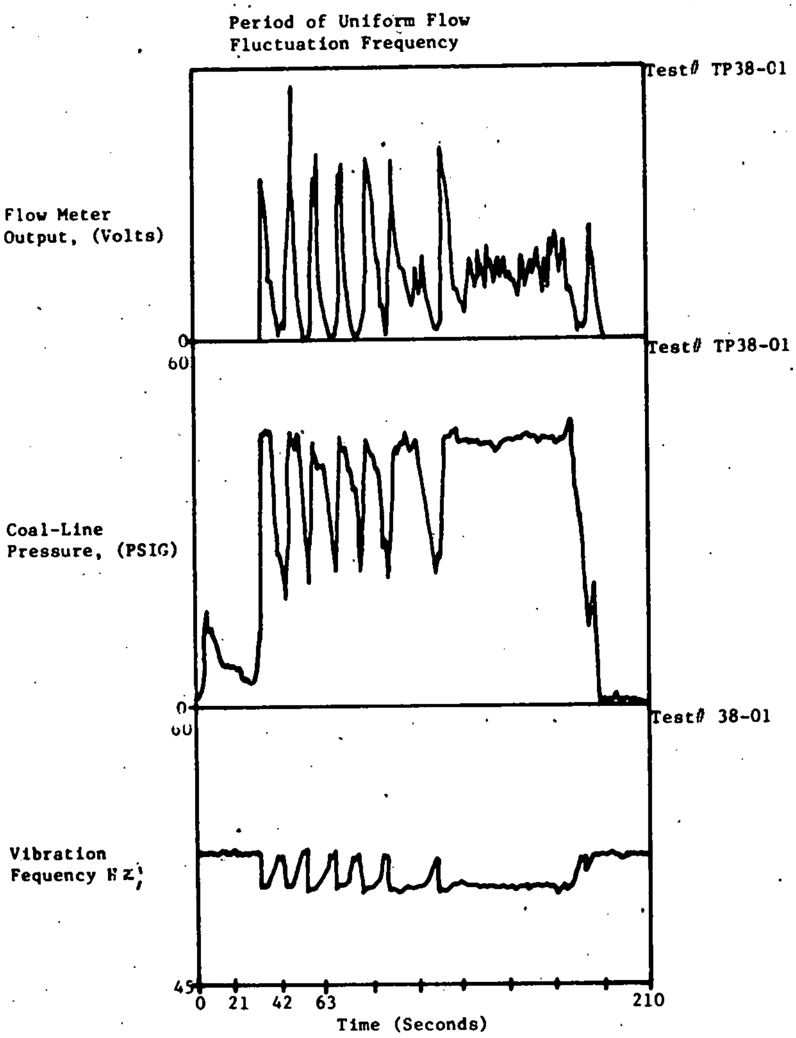


Figure 10. Time Plots to show Correlation Among Flow-Meter Output, Coal Line Pressure and Flow-Meter Vibration Frequency

correlate with the large fluctuations in flow meter output voltage and coal line pressure. These last three figures taken together indicate that during this time period the coal was flowing in a very unstable fashion in such a way that alternate slugs of coal and transport gas were flowing through the flow meter and pressure transducer to give rise to the large fluctuations in flow meter output voltage and pressure transducer response. Thus, the good correlation between flow meter output voltage and coal line pressure shows that the mass flow meter is indeed responding to actual variations in coal flow when it shows these wide fluctuations, so long as the fluctuation frequency is in the range to which the flow meter can respond. It should be noted here that these fluctuations are minimal during the MHD experiment since transport nitrogen is used only to initiate the flow and is shut off once this is achieved.

Looking again at figures 8 and 9 one can conclude that in this system the coal flow becomes increasingly unstable as more and more transport gas is added and that stable flows cannot be obtained for a mixture ratio lower about 128:1. It was expected that flows would become unstable in the intermediate phase regime, but the instabilities were obtained at higher mixture ratios than were expected. This is probably due to the way in which the coal and transport N_2 are mixed. It had originally been planned to proceed to lower mixture ratios down to about 1:1 but these lower ratios could not be easily achieved with the present system so it was decided to continue these experiments at a later time using a system which mixes the coal and transport gas in a more uniform fashion that is more characteristic of the coal delivery system in the Coal Fired Flow Facility, a DOE MHD test facility presently being completed at UTSI.

4. CONCLUSION

The purpose of this study was to evaluate the performance of the coriolis effect mass flow meter as it was applied to the measurement of coal flow at the R&D facility of the Energy Conversion Division at UTSI. This evaluation has successfully demonstrated that the mass flow meter operates very well in the dense phase region in our coal feed system.

A calibration curve was obtained for the meter under these conditions. A summary of the experimental results is given in Table II. Also it was found that even in the lighter phase regions the flow meter appeared to follow the instabilities in coal flow in that is showed good correlation with coal line pressure fluctuations. Also, this study shows the great value of such a mass flow meter in the evaluation of a particular coal delivery system. It showed that for the particular coal delivery system tested, very stable flows could be obtained in the very dense phase region which is used in MHD experiments. It was also shown that the flow became more unstable as the coal: transport gas ratio decreased and became extremely unstable at ratios below 128:1. The performance of this mass flow meter has not been tested at mixture ratios below 50:1 but it is planned that this will be done in the future with an improved coal delivery system.

Table II. SUMMARY OF EXPERIMENTAL RESULTS

Coal Mass Flow (lb/sec)	Nitrogen Mass Flow (lb/sec)	Ratio (Coal/N2)	Hopper Pressure (PSIG)	Coal Line Pressure (PSIG)	Flow Stability
0.45	0	-	60	36	very stable
0.78	0	-	80	46	very stable
1.34	0	-	80	27	very stable
1.2	0.0048	250/1	78	17	stable
0.94	0.0073	128/1	78	23	somewhat unstable
0.76	0.0087	87/1	78	25	unstable
0.6	0.01	60/1	78	25	unstable
0.6	0.012	49/1	78	54	unstable

ACKNOWLEDGEMENT

This work was supported by the Department of Energy under Contract Number DE-AC01-79ET10815.

REFERENCES

1. O'Fallon, N. M. and Le Sage, L. G. "Coal Conversion Instrumentation Industrial Research/Development, June 1978

2. Smith, J. E., "Gyroscopic/Coriolis Mass Flow Meter," Measurements & Control," July-August, 1977

3. Plache, K. O. "Coriolis/Gyroscopic Flow **Meter,"** Mechanical Engineering, March, 1979.

Capacitive Transducers for Mass Flow Measurement, An Overview

by W. W. Managan and R. W. Doering

Argonne National Laboratory

Introduction

The design of a capacitive transducer and associated electronics have been reported, including the results of testing at the HYGAS plant in Chicago, Illinois.[1] This paper presents further analysis of the HYGAS data, including some of the difficulties of the capacitive method followed by results of testing the HYGAS capacitor on a low density solids/gas flow and finally a discussion of two unusual capacitor designs.

The schematic of the HYGAS experiment data acquisition equipment is shown in Fig. 1. Note the separation by approximately 90 meters of the point of measurement from the recording equipment in the instrumentation trailer and the HP 5420A Signal Analyzer. The electrode layout of the capacitor is shown in Figure 2. The inside diameter of the ceramic tube is chosen to maintain a smooth continuity of flow without diameter change from the adjoining pipe sections. The capacitive electrodes are located immediately outside the ceramic tube. The arrangement shown is a parallel plate capacitor, the driven plate at the top and the sensing plate at the bottom. Between these are potential electrodes held at an appropriate fractional voltage by means of a resistance voltage divider. The signal electrode is surrounded by a grounded guard plate and is held very nearly at ground potential. The signal electrode is segmented along the flow direction to provide for a density electrode signal as well as a number of velocity electrode signals with varying separations. Separations in this case range from 15 mm up to 142 mm. A second set of electrodes not shown here increased the maximum separation to 293 mm.

Calibration and Density Effects

The calibration procedure is based on the use of grab samples, admittedly an imprecise method. For an idealized two-phase char/toluene slurry an idealized situation is considered first and secondly some sources of error. The output voltage obtained for different percent by weight solids (PWS) is shown in Fig. 3. The output voltage has the approximately linear form

$$V_{out} \approx 7.3 + 0.1\ (\text{PWS})\ \text{volts}.$$

It is desired to separate this total mass flow output voltage into two separate mass flow measures of the solids and liquids. This is possible for the idealized two-phase system where one has knowledge of the densities of each component. However, if other phases are present, additional information is required.

Starting from the definition of percent by weight solids (PWS) and with a knowledge of the respective densities of the two phases, a table of mass per unit length of pipe versus output voltage can be constructed using the percent by weight solids for the associated grab samples as a transfer function between output voltage and mass per unit length of pipe. Also, when the percent by weight solids is zero, the output voltage will be entirely due to the liquid. These relationships are shown in Fig. 4 in which the total mass per unit length is displayed as a function of the measured output voltage. Given the known densities of the liquid and solid phases, their respective mass flows per unit length can be obtained by multiplying the mass per unit length by the velocity through the pipe.

This is a linear approximation. It should be noted however that the curves are definitely nonlinear. The output voltage as a function of percent by weight solids was approximately linear, leading one to expect the bulk density of the grab samples to have an approximately linear relationship with the percent solids by weight. However, Fig. 5 shows a large scatter in the data. In fact, the scatter is so large compared to the precision of the measurements as to raise the question whether a third phase may not be present. This hypothesis was strengthened by noting that in some of the grab samples a portion of the solids actually floated on the solvent. This was attributed to non-wetting of those solids by the solvent, resulting in the porosities of the solids being filled with voids rather than with solvent, thereby reducing the apparent bulk density.

Assuming the volume and density measurements on the grab samples were relatively precise, it was possible to estimate the void fraction for each grab sample and to calculate a revised bulk density. When this correction is applied the scatter is almost completely eliminated as shown in Fig. 5. Thus the conclusion is reached that in a number of the samples a third phase was indeed present as voids or gas.

Velocity Signals

The velocity signals are processed by a Hewlett Packard Model 5420A signal analyzer. The cross correlation output is a correlogram as shown in Fig. 6. The peak of the correlogram corresponds to the average delay time or transit time between the two velocity electrodes.[2] Dividing the electrode separation, L, by transit time, τ, an estimate of the stream velocity $V = L/\tau$, is obtained. In this particular instance the stream velocity was approximately 4 meters per second.

During a period of steady operation in the HYGAS experiment, a series of correlograms were taken for all of the combinations of electrode separation. The transit times for these are shown in Fig. 7. A least squares fitted straight line is shown. The reciprocal of the slope gives the velocity at 4.1 meters per second. The correlation coefficient approaches unity indicating a high level of internal consistency in the data; that is, all of the electrode pairs indicate the same velocity.

It was found that the different electrode pairs did not provide the same time resolution. The correlogram as shown in Fig. 8 may be characterized by the full width at half maximum (FWHM), the average delay time, τ, and the time resolution defined as the ratio of the full width at half maximum (FWHM) and average time delay τ, Resolution = (FWHM/τ). Small values of resolution are desired. Several values of time resolution are shown in Fig. 9 as a function of the electrode spacing. The correlogram in Fig. 6 has an estimated FWHM of 80 milliseconds and an average delay τ of about 4.4 milliseconds, giving a time resolution of 18 for an electrode separation of 15 mm. Larger electrode separations showed significant reductions in time resolution, the FWHM being reduced while the mean delay or transit time was increasing. The solids-liquid curve denoted by the squares is for the HYGAS solids/liquid feed slurry. The pipe inside diameter is approximately 54 mm. In this experiment a significant improvement in time resolution is obtained by increasing the electrode spacing to at least 1, and preferably 2 or 3, pipe diameters. For low velocity flow at HYGAS, the time resolutions became large (poor), especially for large electrode separations.

When the same capacitor was installed and tested on the solids/gas flow test facility (S/GFTF) at the Argonne National Laboratory, it was found that the higher velocity (16-24 meters per second) led to velocity signals with much higher frequency components as shown in Fig. 10 and correspondingly better time delay resolution. Typical FWHM ranged from 0.5 to 1.6, as shown in Fig. 9. The effect is most pronounced for small electrode separations. Having dealt with the information in the time domain, let us proceed to examine similar information in the frequency domain.

A convenient means is to use the transfer function of the HP 5420A signal analyzer. This views the velocity signals at capacitor A as the input being transferred through the pipe to the capacitive electrode at B some distance, L, downstream. Before leaving the time domain, typical solid/gas time domain signals are shown in Fig. 10. The expanded scale 0-100 msec permits the transit delay τ to be seen. The autospectra are shown in Fig. 11. The transfer function over a range of 0-3 kHz is shown in Fig. 12 along with a coherence function. The transfer function is seen to be fairly constant over the low frequency portion, falling off at higher frequencies. The coherence function is also relatively constant at very low frequencies but falls off at higher frequencies with a much lower cutoff frequency than the transfer characteristic. The coherence function is a measure from 0 to 1 of the causality of B from A; that is, a measure that the output at B is caused by the input at A. Where the coherence function goes to very small value, one can say that there is a very small probability that the output at B as seen in the transfer function is caused by A. Conversely, where the coherence is greater than a half, or preferably greater input at A. Let us adopt the concept that a limiting frequency can be defined in terms of a coherence limit at constant velocity for different electrode separations or for different velocities between the same electrode pair.

Another physical interpretation of the transfer concept with a constant time delay between A and B is that the phase angle between the signals at A and B will increase linearly with the frequency of the correlated signal components. We shall return to this later.

Adopting the concept of an upper frequency limit for coherence values equal or greater than 0.5 and 0.8, we are able to replot the data as upper frequency limit versus electrode spacing as shown in Fig. 13. Here we see an exponential decay of the upper frequency limit with increasing spatial separation of the electrodes.

Another interpretation of Fig. 13 is in terms of the nature of turbulent flow. A characteristic of turbulent flow is the formation of vortices of varying sizes along the pipe.[3] To a crude approximation each vortex has its maximum amplitude and highest frequency content at the time of formation. It loses energy and frequency content exponentially with distance as it is swept downstream from the point of formation. Thus, the exponential decay observed in Fig. 13 is in keeping with this theoretical model. This leads into the next topic, spatial filtering.

Spatial Filtering

Passage of a discrete fluctuation (such as a bubble) creates a signal in the time domain which can be analyzed or transformed into its Fourier components in the frequency domain. The output signal from an electrode is the integral of all the frequency components which it subtends. The dimension of the electrode.along the flow direction may be thought of as the integration limits over the portion of a wavelength subtended at each frequency. The signal goes to zero when the electrode subtends one or an integral number of wavelengths. As an example, at frequencies of 10, 100, and 1000 Hz and a velocity of 4 meters per second, the longest wavelengths for zero signal are 400, 40, and 4 mm, respectively. Consider a 15 mm long electrode. It will subtend one wavelength of 15mm and have zero output at approximately 266 Hz.

Considering the density electrode which has a length of 121 mm, the frequency at which one wavelength will be subtended is 33 Hz.

The expected minimmum near 38 Hz for solids/liquid flow past a 121 mm long electrode is shown in the transfer, coherence and phase functions in Figs. 14 and 15. Indication of a second harmonic minimum near 76 Hz is seen in Fig. 14. For a 15 mm long electrode in the same solids/liquid flow, a minimum near 266 Hz is shown in Fig. 16.

Moving to a similar consideration of solids/gas flow the velocity is significantly higher, being in the range of 16-24 meters per second. Here a 15 mm long electrode and wavelength will have zero output at frequencies of approximately 1 kHz to 1.5 kHz. Similarly, the density electrode of length 121 mm will have zero output at a frequency of 132 Hz to 200 Hz. The expected minima near 160 Hz and 1.5 Hz for the 121 and 15 mm long electrodes in solids/gas flow are shown in Figs. 12, 17, and 18.

The idea that electrodes act as filters is confirmed. They have unresolved nulls at wavelengths proportional to their length independent of the stream velocity --- or at frequencies inversely proportional to their length but directly proportional to velocity. This is an important design consideration. Another important design consideration is spatial averaging.

Spatial Averaging

The concept of spatial frequency or wavelength filtering has been mentioned in connection with electrode length and the velocity of the flowing medium. A different problem occurs where there are inhomogeneities, slugflow, or stratification of the two phases between the electrodes of the capacitor. Here the problem is to obtain an average over a three dimensional cylindrical volume (pipe section) which is independent of the geometrical distribution of the two phases within that volume.

The electrode design of the HYGAS parallel plate capacitor was intended to provide a uniform electric field and thereby relatively uniform sensitivity throughout the volume subtended by the density electrode. In addition, the density electrode was made several diameters long so as to provide some smoothing (averaging) of inhomogeneities. A typical cross sectional electric field map is shown in Fig. 19 for the HYGAS capacitor. Consider the effect of a bubble appearing at different positions in this field map. The effect in terms of the number of field lines terminating on the sensing electrode is not the same for all positions of the bubble nor is it proportional to the size of the bubble. Stratified liquid partially filling a horizontal section is another severe case. This is a volume sampling problem which has long been recognized. Within the last few years, two interesting and quite different capacitive sensors for attacking this problem have been devised: one is the use of a rotating electric field over a defined length; the other is the use of a helical set of electrodes having exactly an integral number of terms.

Rotating Electric Field Capacitive Transducer

The Auburn International Company offers its Model 1090 volume fraction monitor for fractions of two non-conductive phases having different dielectric constants in a circular pipe cross section.[4] The sensing technique employs six capacitor plates located around the circumference of a non-conductive pipe section. As shown in Fig. 20, a field is developed across the cross section by driving one plate and receiving on the opposite three plates. The field is "rotated" through the cross section at 938 revolutions per second, by essentially shifting the electrical position of the plates.

The averaged capacitance value produces a signal proportional to the volume fraction of one phase. This signal is indicated by a meter as well as a 0-10 volt output signal. A "zero" control is provided for nulling the capacitance of the phase with the lower dielectric constant. A "span" control is provided for scale adjustment due to the capacitance of the phase with the higher dielectric consta

During the past year tests of this instrument have been conducted at a number of facilities including the Pittsburgh Energy Technology Center by Dr. Hendro Matur with favorable results where only two phases were present.

A conductivity variation of this concept is also offered by the Auburn International Company.

The Helical Capacitor

The helical capacitor concept was described by Gregory in 1973 and more recently by his associates at the University of Calgary.[5,6] Gregory introduced the helical sensor to measure the in-situ volume fractions in petroleum pipeline situations. The helical sensor provides a nearly linear measure of the percentage by volume of oil or water in a two-phase flow independently of the geometrical distribution of the two phases within the pipe.[6]

The use of an integral number of turns in the helix is a key factor in providing this freedom from sensitivity to the location of the phases within the pipe.

The mechanical layout of the electrodes is shown in Fig. 21. The two electrodes are wound helically around a thin, dielectric tube section such that they are always opposite each other, and are cemented in place. A thicker insulating tube section covered with the metal foil shield is fitted over the initial section, and this shielded electrode assembly is enclosed between appropriate mounting flanges.

Electrical connections are made to the helical electrodes by means of spring loaded coaxial cable connectors, the outer portion of each being in contact with the outer metallic shield.

Conclusions

1. Parallel plate capacitance transducers have been shown to provide useful measures of density and velocity for two-phase non-conductive flows over a density range from 0.005 g/cm^3 for solids/gas flows to about 1.2 g/cm^3 for solids/liquid flows. The velocity measurement improves with increasing velocity.
2. Presence of a third phase renders the density output indeterminate but does not necessarily degrade the velocity signals.
3. Uniformity of capacitive sampling of two-phase non-conductive flows over a length of pipe may be significantly improved over parallel plate electrodes by using a rotating electric field design or a helical capacitor design where the helix has an integral number of turns.
4. Spatial filtering by the electrodes is an important design consideration.

ACKNOWLEDGEMENTS

The authors would like to thank T. K. Lau, DOE-FE, N. M. O'Fallon and L. G. LeSage for their encouragement and counsel; the IGT HYGAS pilot plant staff; T. Pienias, ENG, for the mechanical design; J. Eichholz, EL, for design of and R. Bannon, EL, for construction of the electronics; E. F. Groh, AP, and E. Lewandowski, CS, for construction and assembly of the instrument; and finally J. Wiesemes, EL, and M. Marciniak, AP, for assistance with the testing.

LIST OF FIGURES

REFERENCES

1. "Field Test of a Capacitive Transducer for Density/Velocity (Mass Flow) Measurement on the HYGAS Pilot Plant Solvent/Coal Feedline," W. W. Managan, J. J. Eichholz, and R. W. Doering. Proceedings of the 1978 Symposium on Instrumentation and Control for Fossil Demonstration Plants, held June 19-21, 1978, Neport Beach, California, report number ANL-78-62, available from NTIS; Price: Printed copy $21.50, Microfiche $3.00.

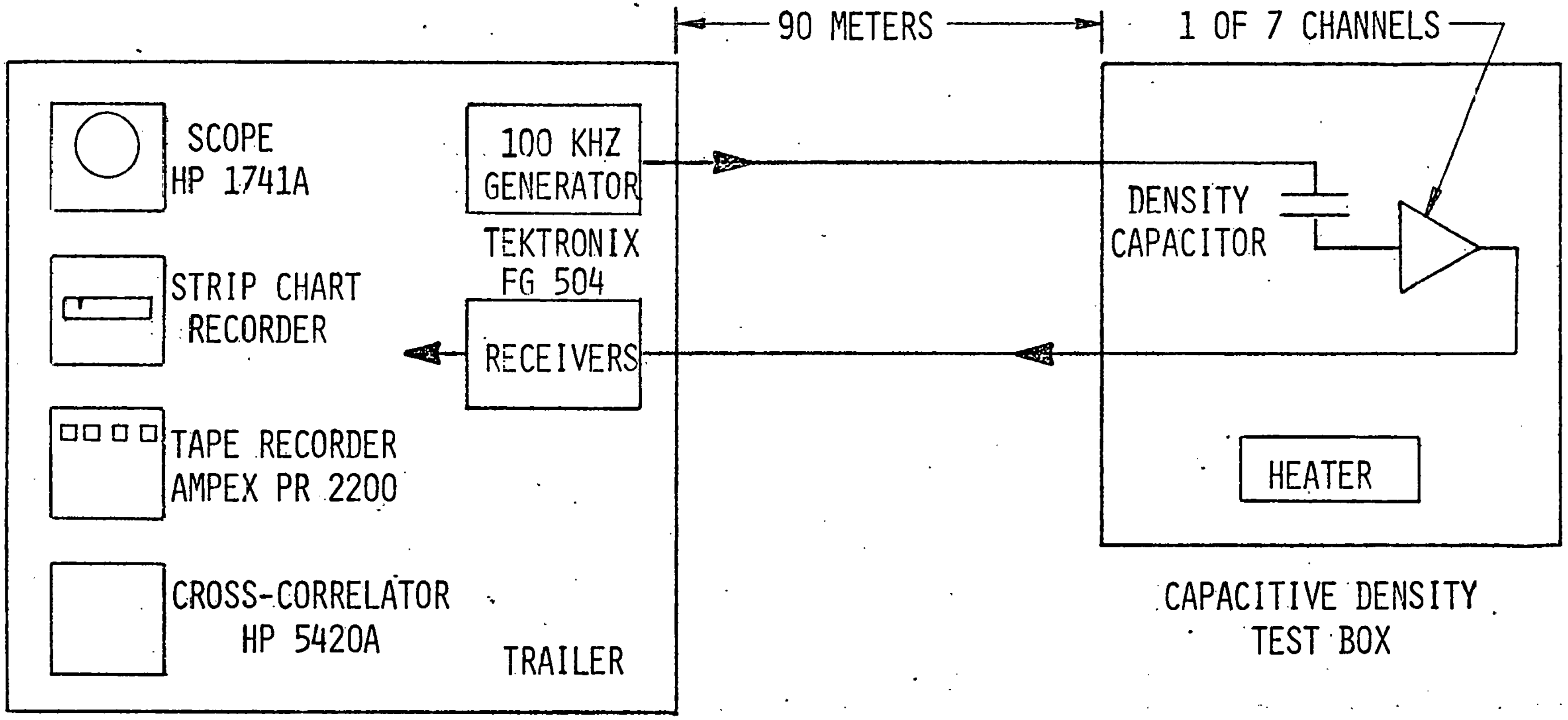
2. "Estimation and Reduction of Errors in Flow Measurements which Use Cross-Correlation Techniques," H. Bazerghi, K. J. Serdula, in Progress in Nuclear Energy, Vol. 1, pp. 629-648, Pergamon Press, 1977.

3. "Some Measurements of Particle Velocity Autocorrelation Functions in a Turbulent Flow," W. H. Snyder and J. H. Lumley, Journal of Fluid Mechanics, Vol. 48, Part 1, pp. 41-71 (1971).

4. The Auburn International Company, One Southside Road, Danvers, Mass 01923.

5. "An In-Situ Volume Fraction Sensor for Two-Phase Flows of Non-Electrolytes," G. A. Gregory, L. Mattar, Journal of Can. Pet. Tech., 12, 48 (1973).

6. "Analysis and Design of Helical Capacitance Sensors for Volume Fraction Determination," M. S. A. Albouelwafa, E. J. M. Kendall, Rev. Sci. Instr., 50, 872, 1979.



NOTE: ALL CABLES HOUSED IN METAL CONDUIT, HEATER AND THERMOSTAT CONTROL FOR 30°C

Fig. 1

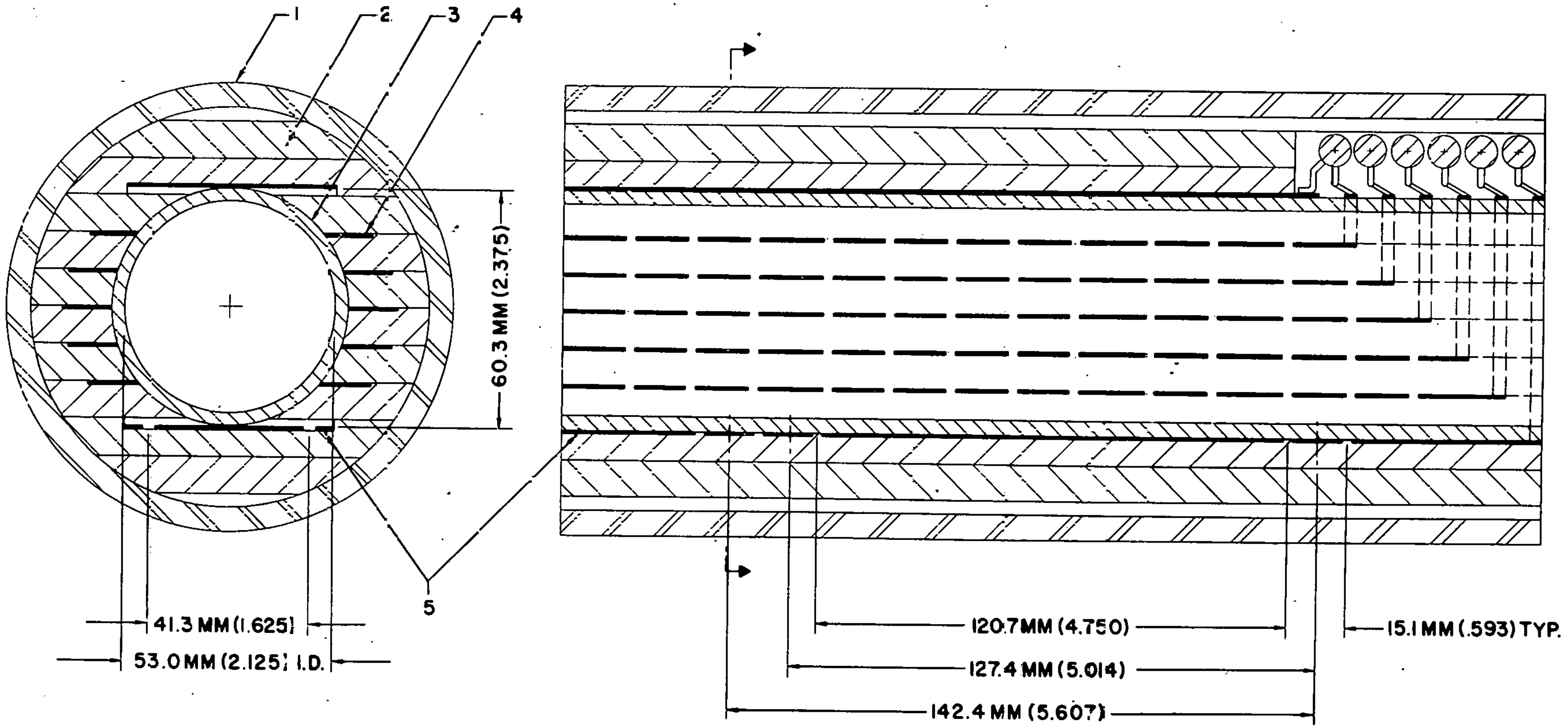

1
2
3
4
60.3 MM (2.375)
5
41.3 MM (1.625)
53.0 MM (2.125) I.D.
120.7 MM (4.750)
15.1 MM (.593) TYP.
127.4 MM (5.014)
142.4 MM (5.607)

Fig. 2

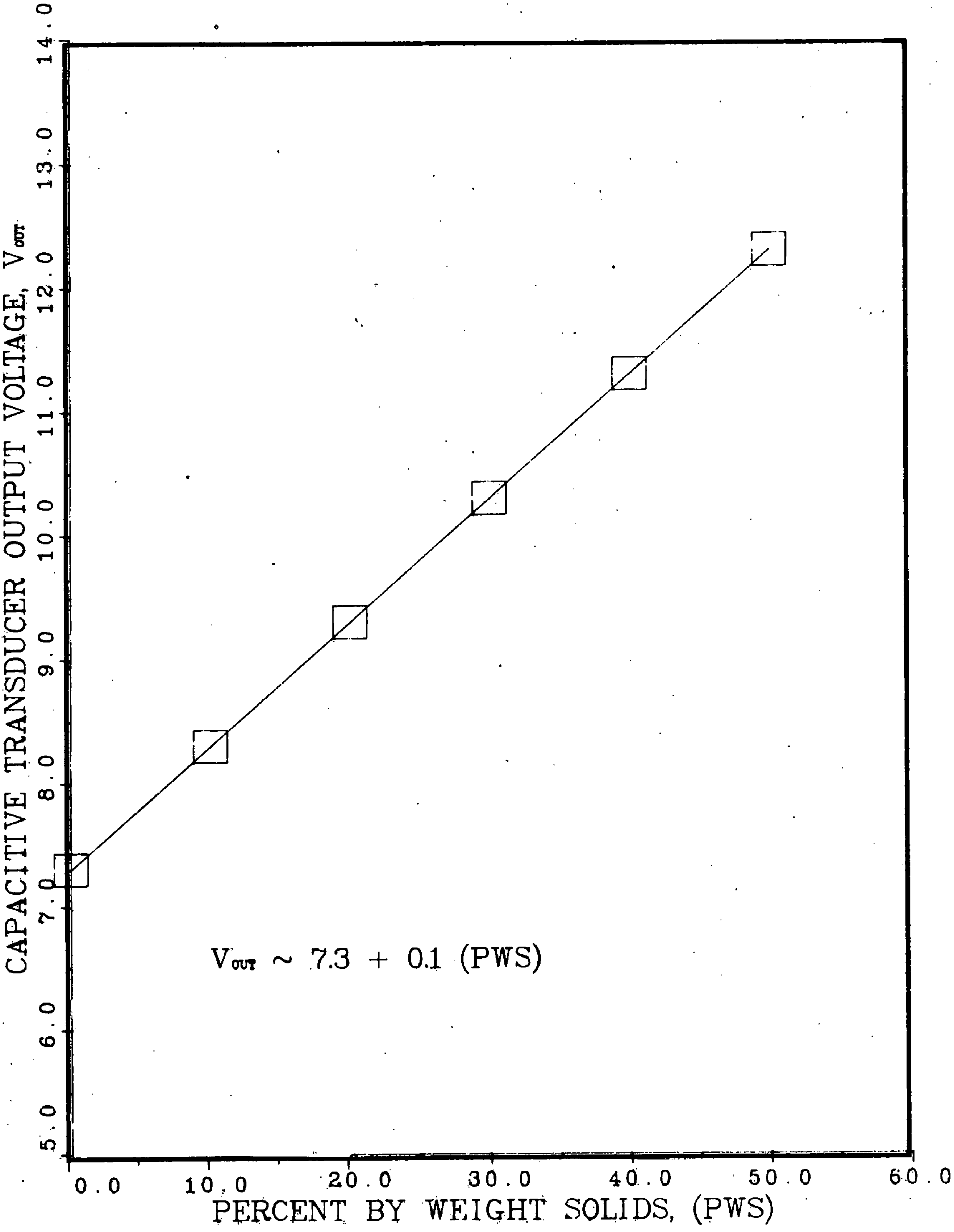

CAPACITIVE TRANSDUCER OUTPUT VOLTAGE, V_{OUT}
5.0
6.0
7.0
8.0
9.0
10.0
11.0
12.0
13.0
14.0
$V_{OUT} \sim 7.3 + 0.1$ (PWS)
0.0
10.0
20.0
30.0
40.0
50.0
60.0
PERCENT BY WEIGHT SOLIDS, (PWS)

Fig. 3

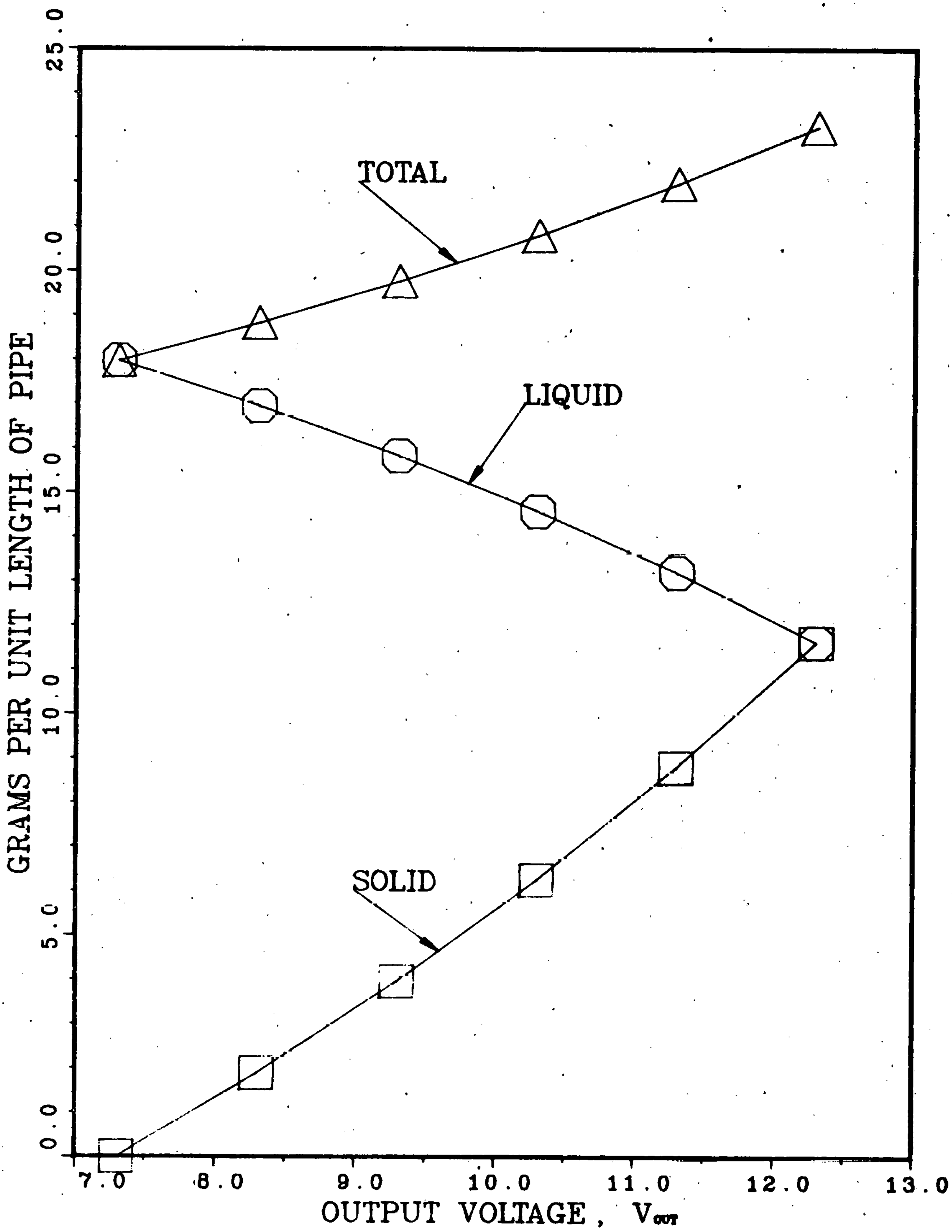

TOTAL
LIQUID
SOLID
GRAMS PER UNIT LENGTH OF PIPE
0.0
5.0
10.0
15.0
20.0
25.0
7.0
8.0
9.0
10.0
11.0
12.0
13.0
OUTPUT VOLTAGE , V_{out}

Fig. 4

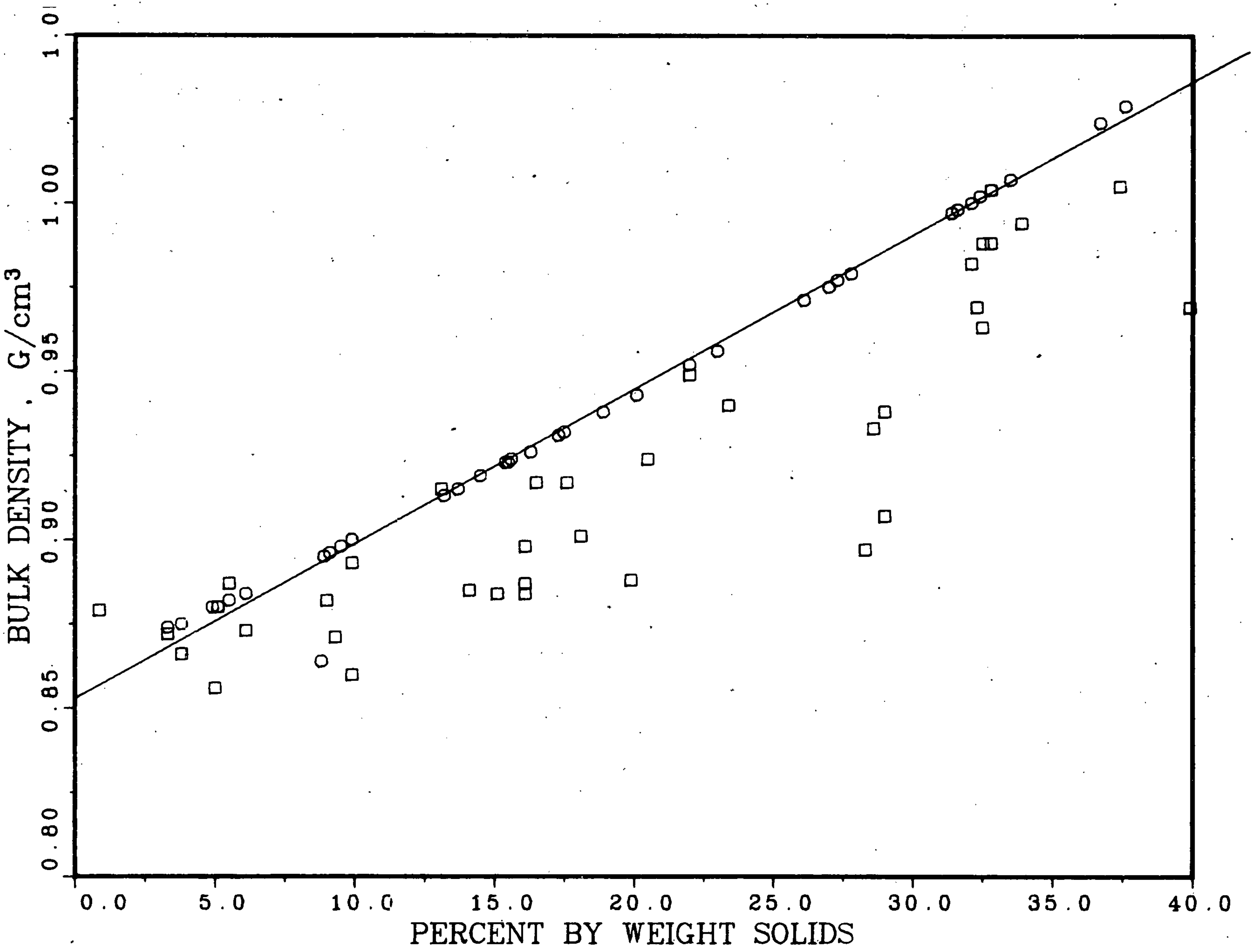

BULK DENSITY , G/cm^3
0.80
0.85
0.90
0.95
1.00
1.0
0.0
5.0
10.0
15.0
20.0
25.0
30.0
35.0
40.0
PERCENT BY WEIGHT SOLIDS

Fig. 5

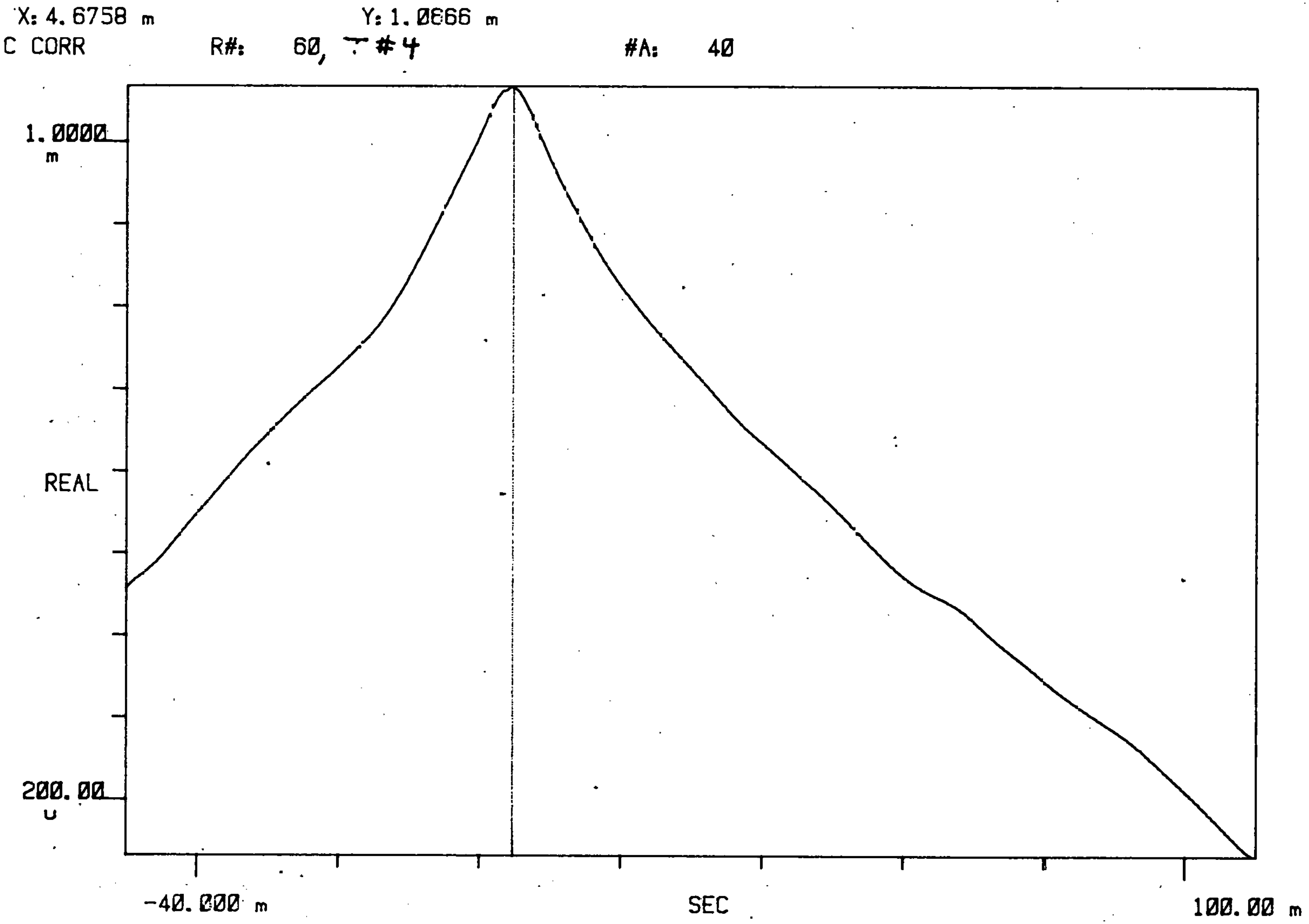

X: 4.6758 m
Y: 1.0666 m
C CORR
R#: 60, T#4
#A: 40
1.0000 m
REAL
200.00 u
-40.000 m
SEC
100.00 m

Fig. 6

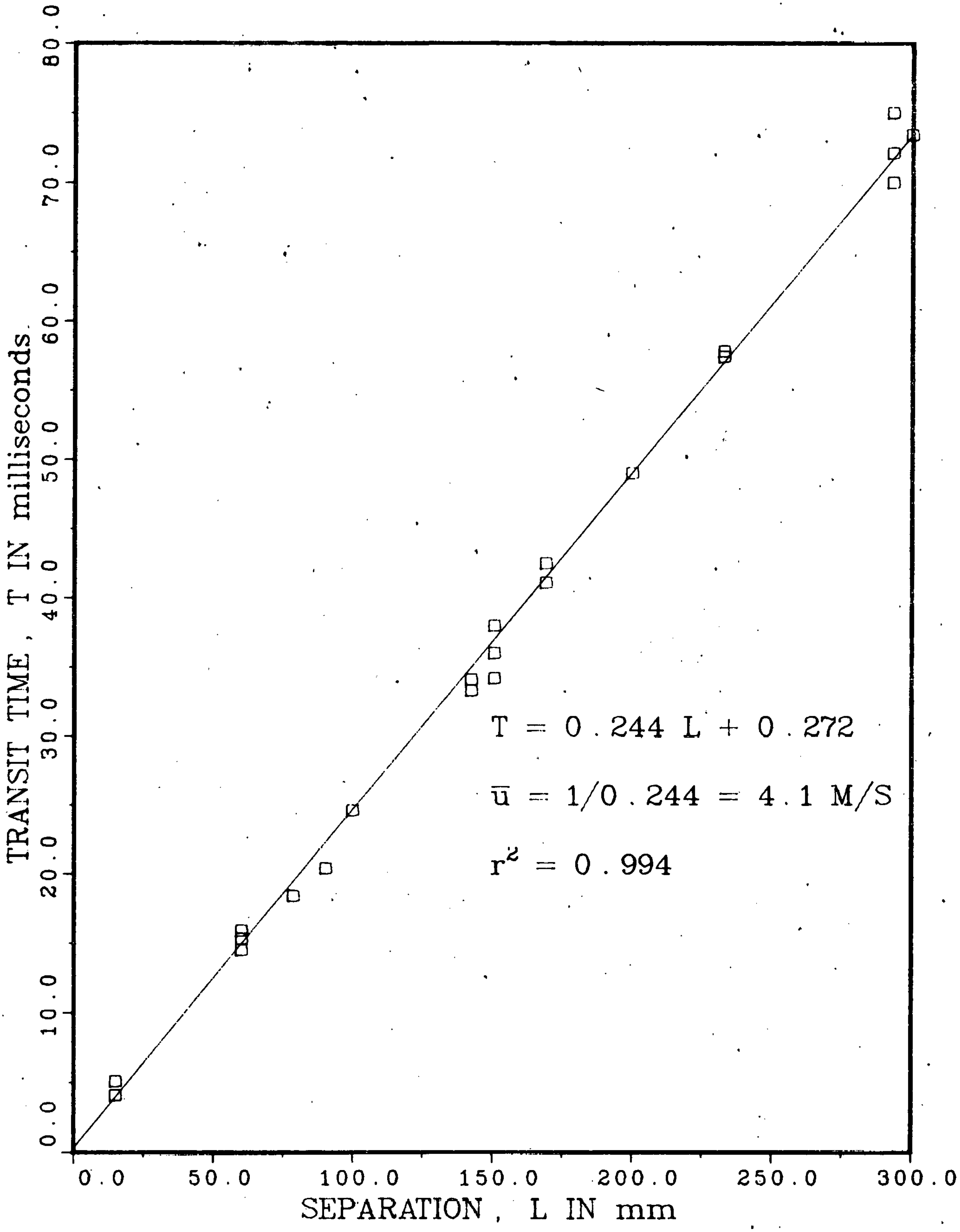

TRANSIT TIME VS ELECTRODE SPACING

Fig. 7

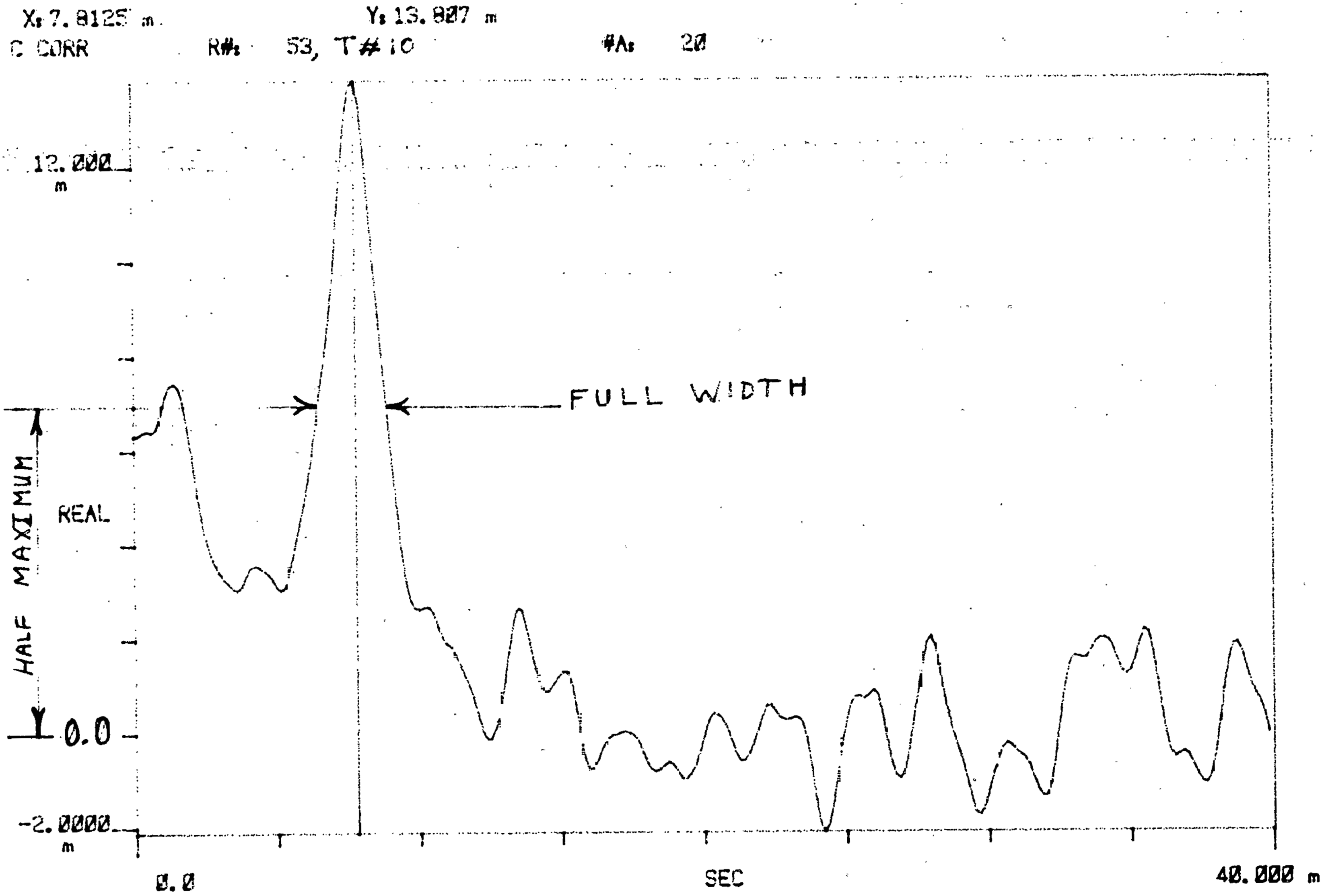

X: 7.8125 m
Y: 13.807 m
C CORR
R#: 53, T#10
#A: 20
12.000 m
0.0
-2.0000 m
REAL
HALF MAXIMUM
FULL WIDTH
0.0
SEC
40.000 m

Fig. 8

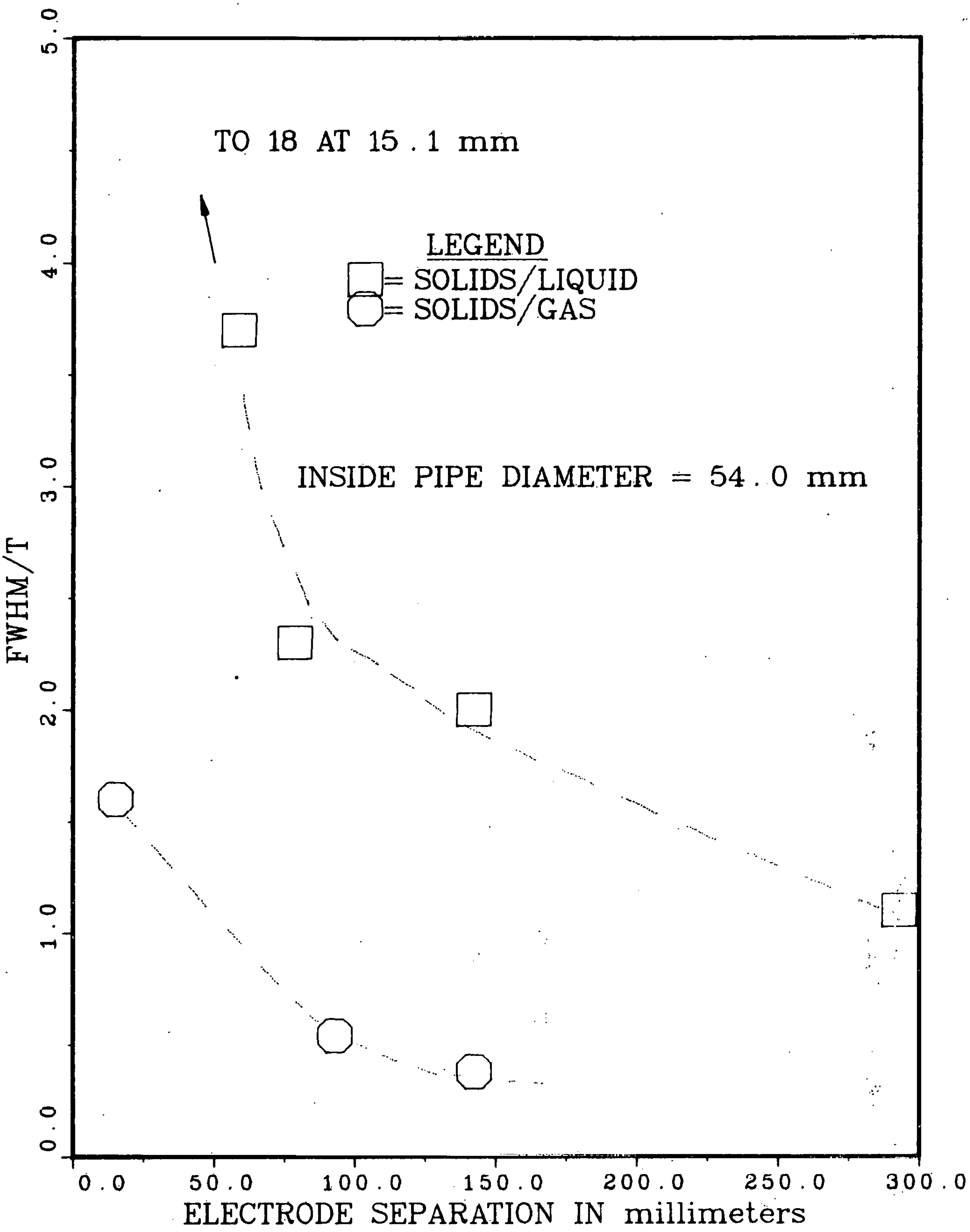

TO 18 AT 15.1 mm
LEGEND
□ = SOLIDS/LIQUID
○ = SOLIDS/GAS
INSIDE PIPE DIAMETER = 54.0 mm
FWHM/T
0.0
1.0
2.0
3.0
4.0
5.0
0.0
50.0
100.0
150.0
200.0
250.0
300.0
ELECTRODE SEPARATION IN millimeters

Fig. 9

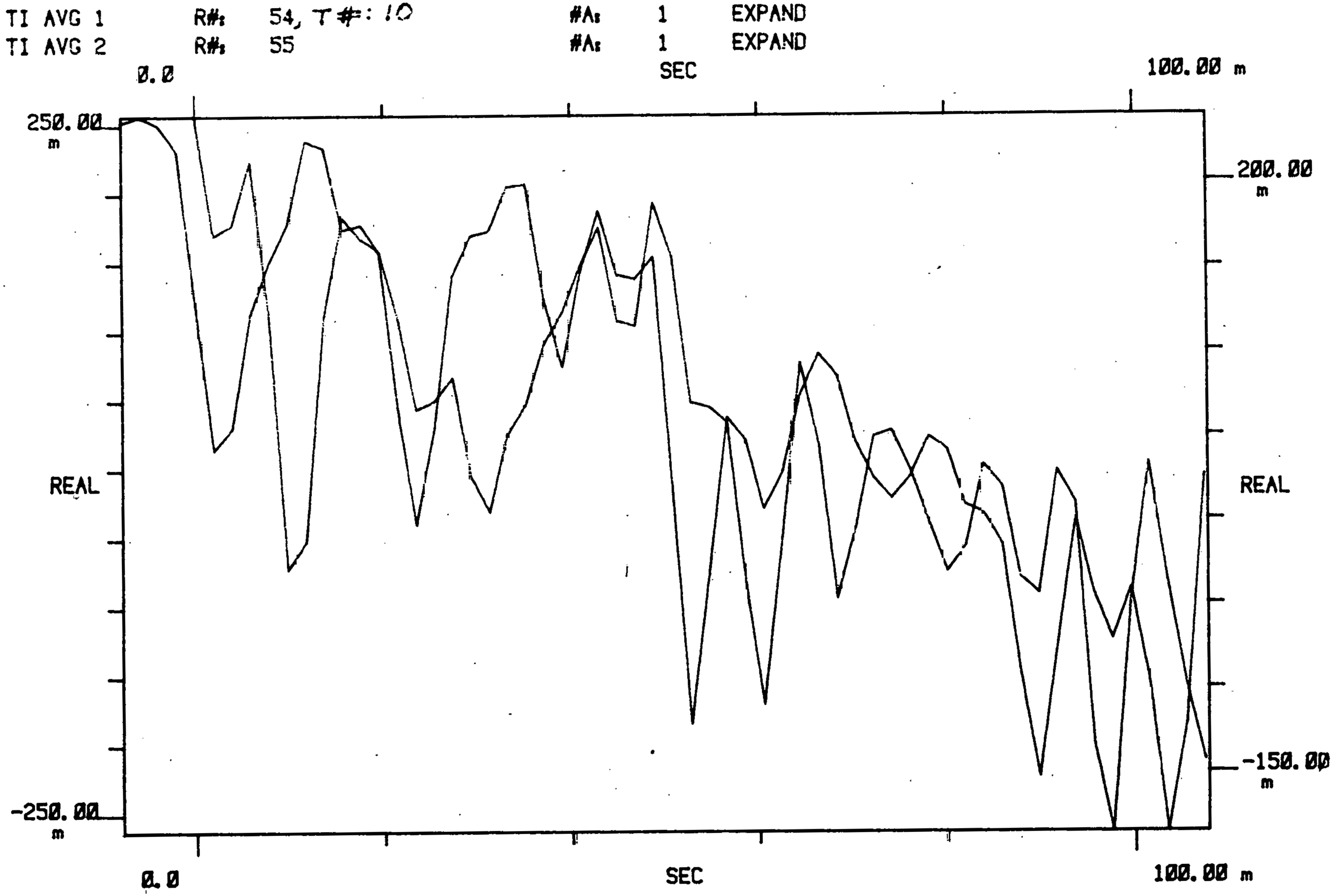

TI AVG 1 R#: 54, T#: 10 #A: 1 EXPAND
TI AVG 2 R#: 55 #A: 1 EXPAND
0.0
SEC
100.00 m
250.00 m
-250.00 m
REAL
200.00 m
-150.00 m
REAL
0.0
SEC
100.00 m

Fig. 10

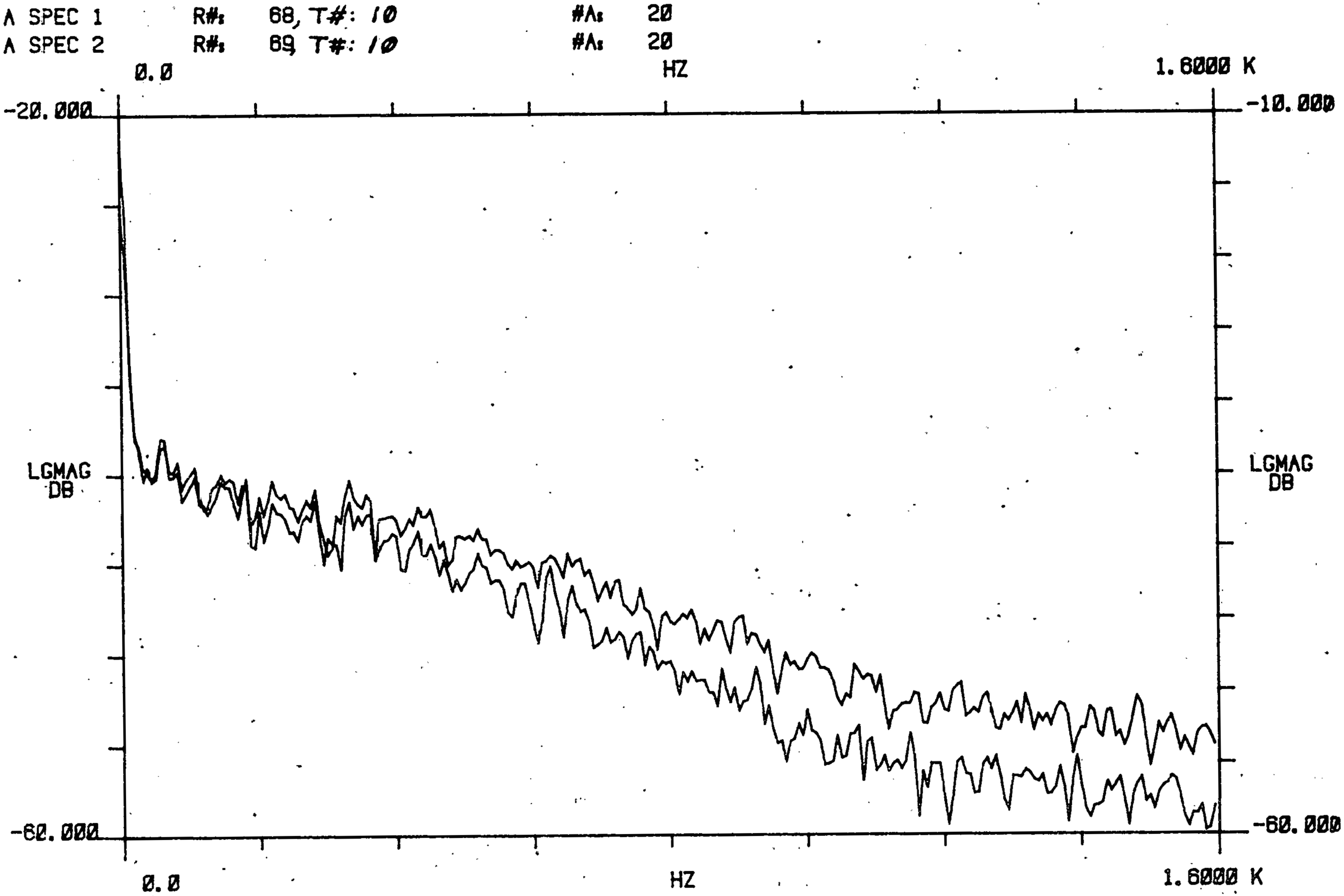

A SPEC 1 R#: 68, T#: 10 #A: 20
A SPEC 2 R#: 69, T#: 10 #A: 20
0.0
HZ
1.6000 K
-20.000
-10.000
LGMAG DB
LGMAG DB
-60.000
-60.000
0.0
HZ
1.6000 K

Fig. 11

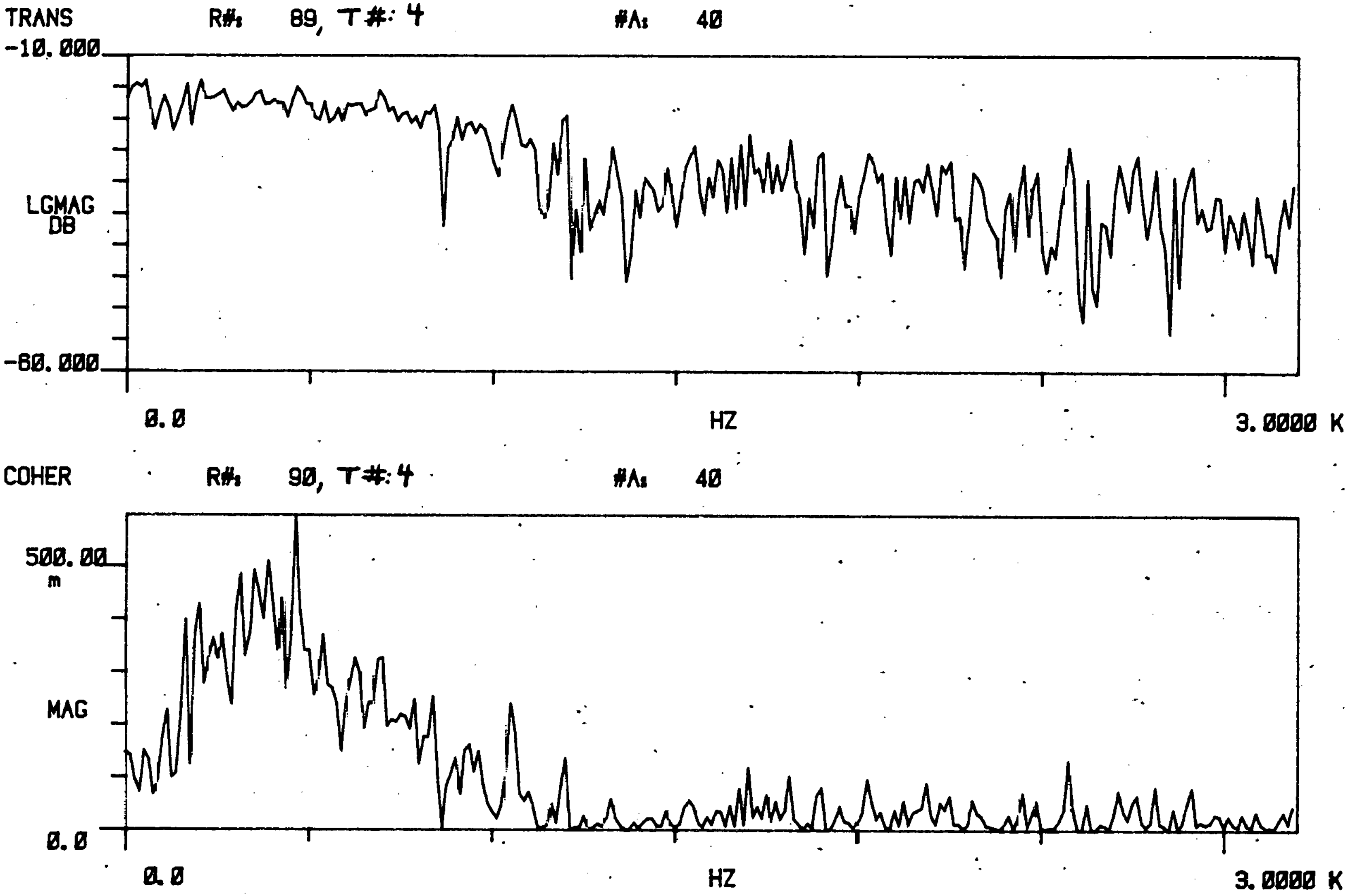

TRANS
R#: 89, T#: 4
#A: 40
-10.000
LGMAG
DB
-60.000
0.0
HZ
3.0000 K
COHER
R#: 90, T#: 4
#A: 40
500.00
m
MAG
0.0
0.0
HZ
3.0000 K

Fig. 12

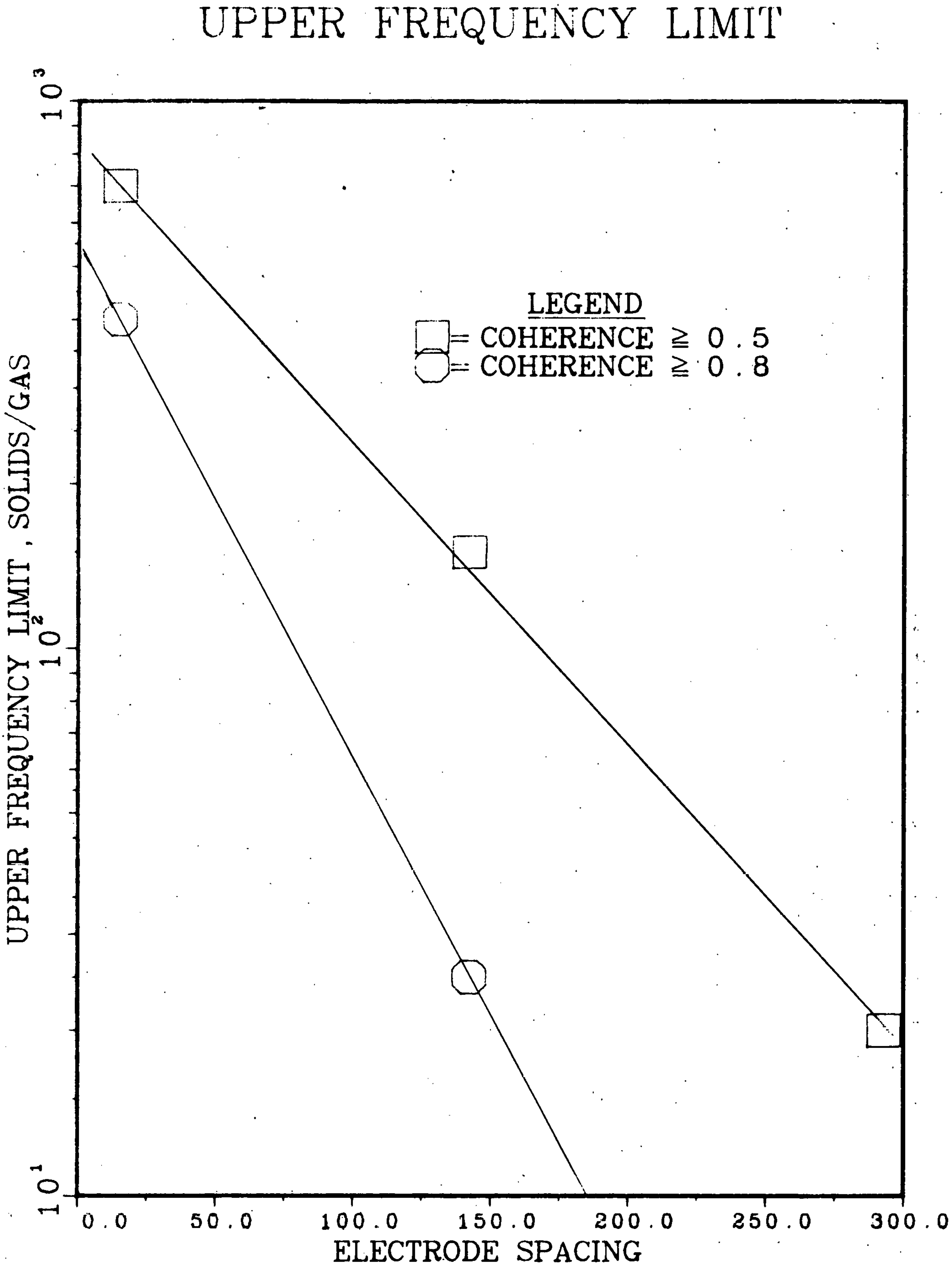

UPPER FREQUENCY LIMIT
UPPER FREQUENCY LIMIT , SOLIDS/GAS
10^3
10^2
10^1
0.0
50.0
100.0
150.0
200.0
250.0
300.0
ELECTRODE SPACING
LEGEND
□ = COHERENCE ≧ 0.5
○ = COHERENCE ≧ 0.8

Fig. 13

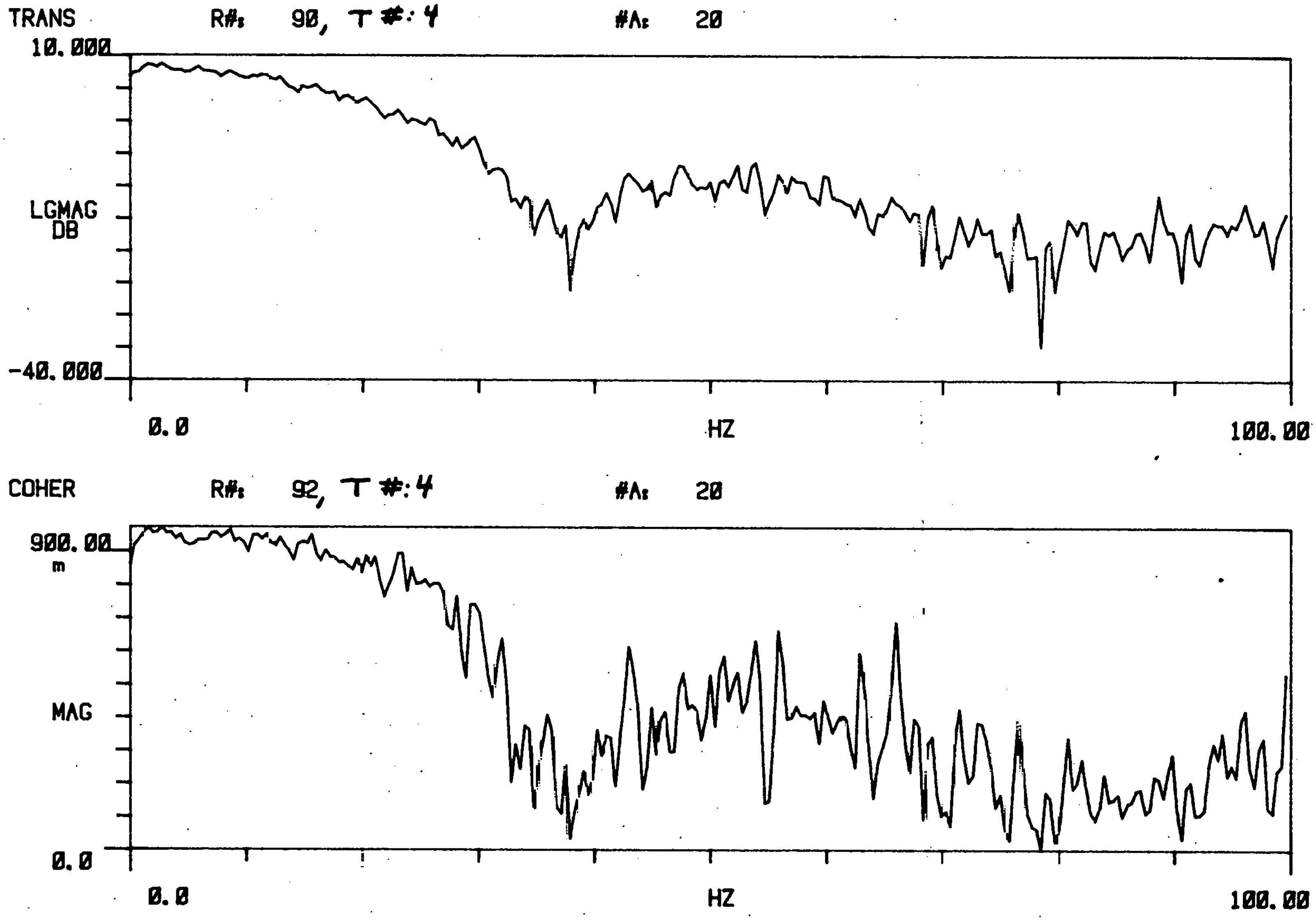

TRANS
R#: 90, T #: 4
#A: 20
10.000
LGMAG
DB
-40.000
0.0
HZ
100.00
COHER
R#: 92, T #: 4
#A: 20
900.00
m
MAG
0.0
0.0
HZ
100.00

Fig. 14

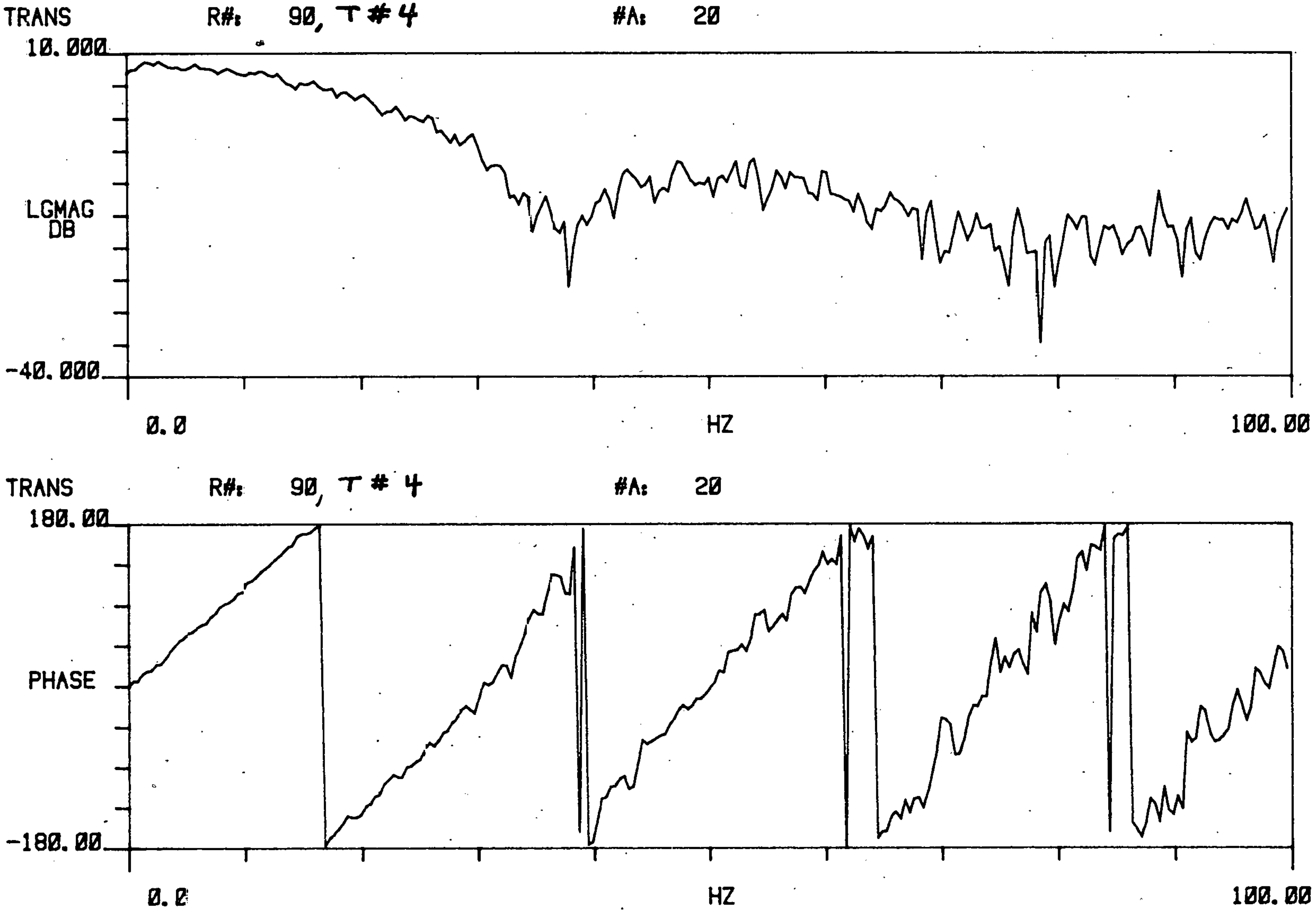

TRANS
R#: 90, T#4
#A: 20
10.000
LGMAG
DB
-40.000
0.0
HZ
100.00
TRANS
R#: 90, T#4
#A: 20
180.00
PHASE
-180.00
0.0
HZ
100.00

Fig. 15

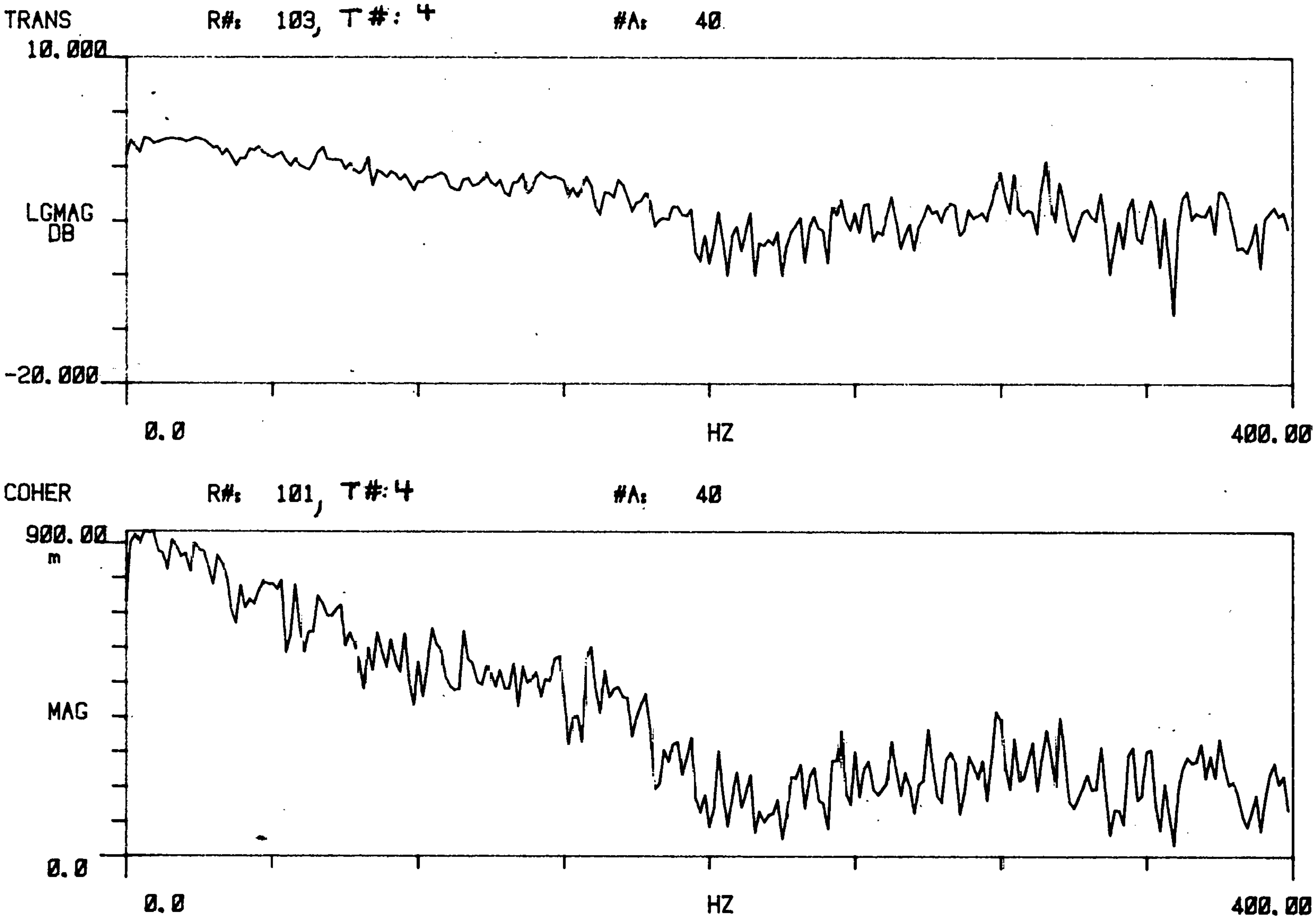

TRANS
R#: 103, T#: 4
#A: 40
10.000
LGMAG
DB
-20.000
0.0
HZ
400.00
COHER
R#: 101, T#: 4
#A: 40
900.00
m
MAG
0.0
0.0
HZ
400.00

Fig. 16

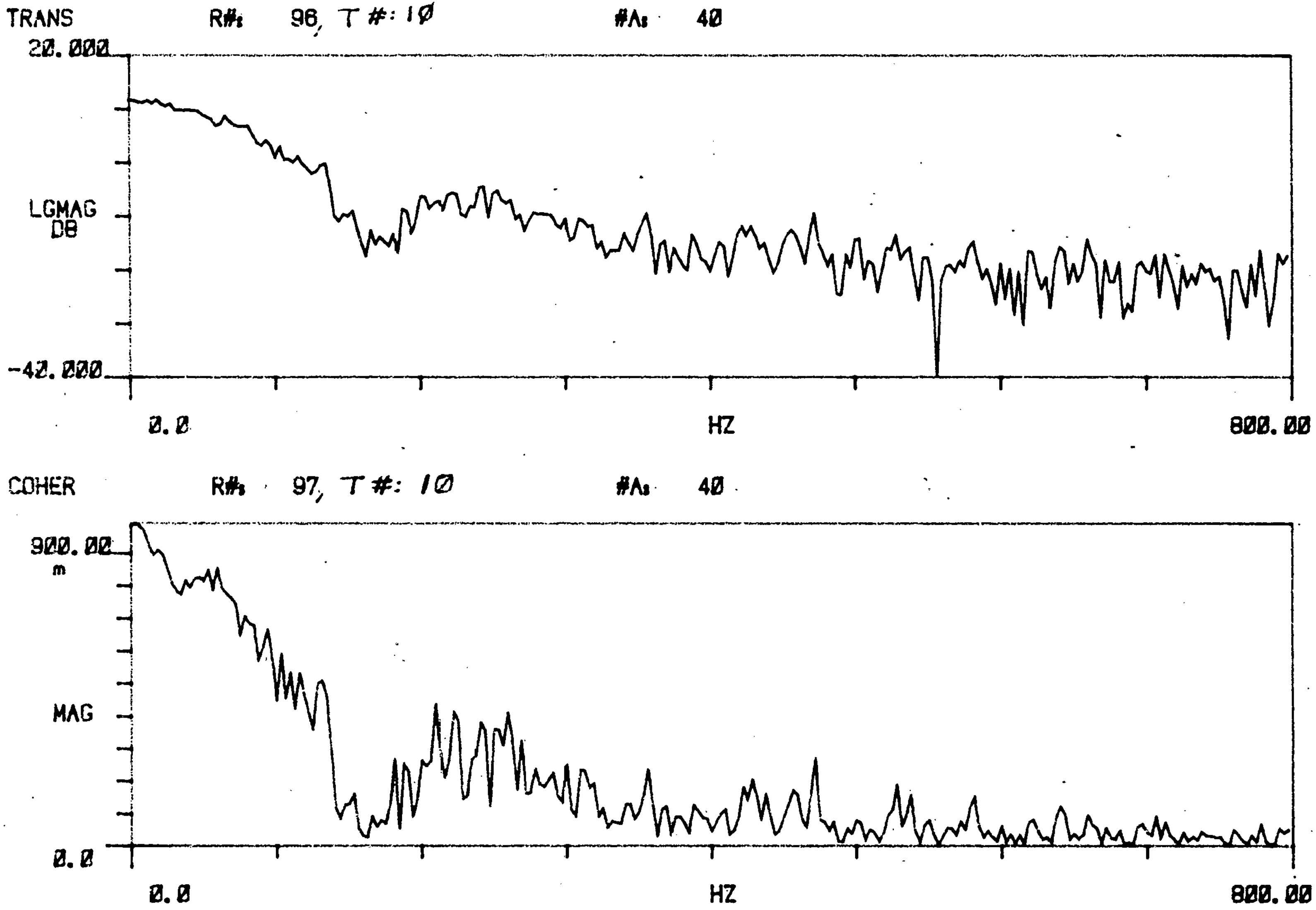

TRANS
R#: 96, T#: 10
#A: 40
20.000
LGMAG
DB
-42.000
0.0
HZ
800.00
COHER
R#: 97, T#: 10
#A: 40
900.00
m
MAG
0.0
0.0
HZ
800.00

Fig. 17

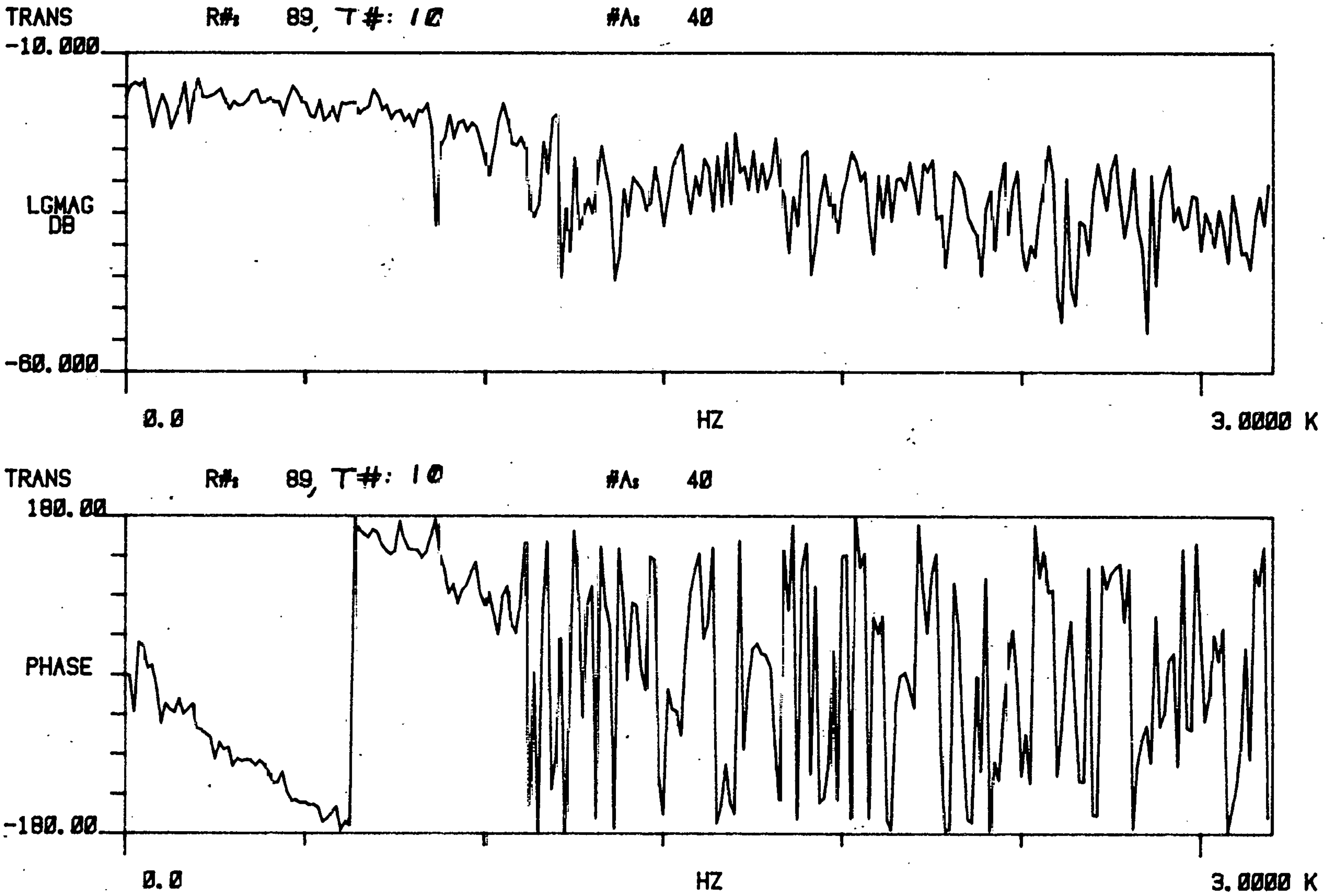

TRANS
R#: 89, T#: 10
#A: 40
-10.000
LGMAG DB
-60.000
0.0
HZ
3.0000 K
TRANS
R#: 89, T#: 10
#A: 40
180.00
PHASE
-180.00
0.0
HZ
3.0000 K

Fig. 18

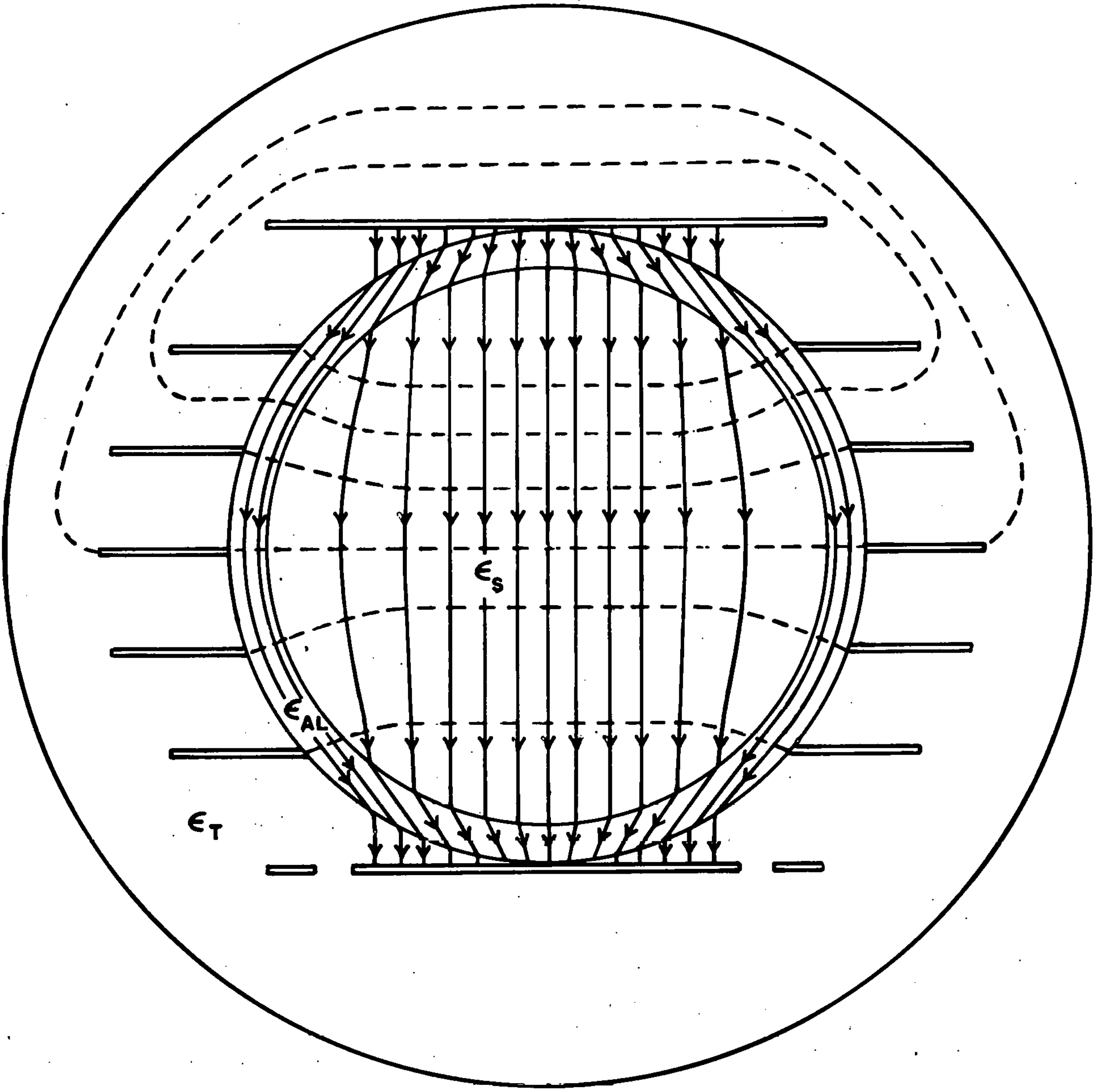
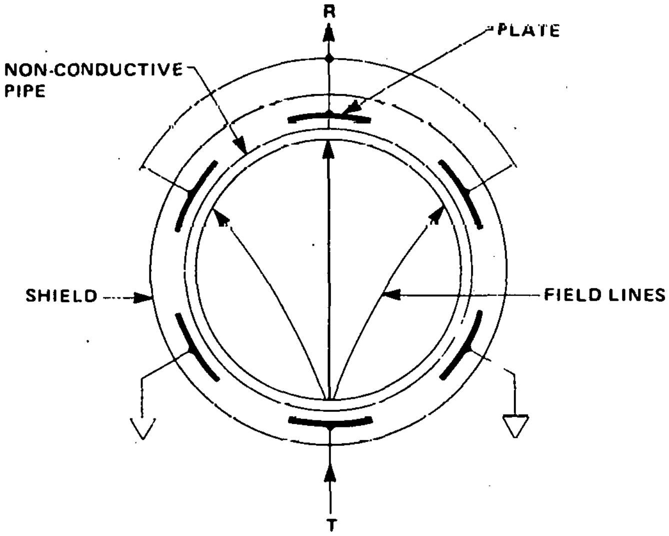


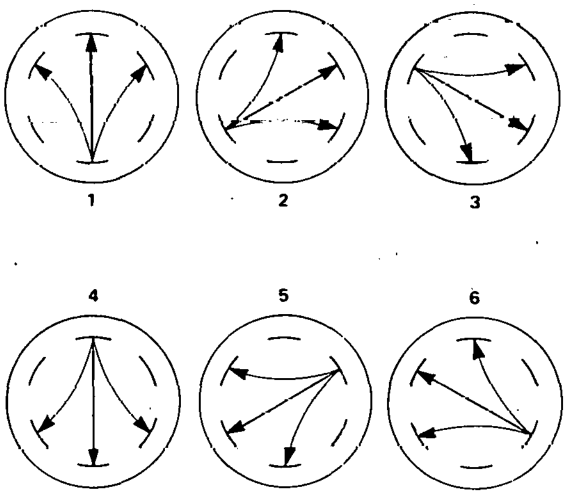
Fig. 19

General Description

The Auburn Model 1090 is designed to monitor the fractions of two non-conductive phases having differing dielectric constants in a circular pipe cross section. The sensing technique employs six capacitor plates located around the circumference of a non-conductive pipe section. As shown below, a field is developed across the cross section by driving one plate and receiving on the opposite three plates. The field is 'rotated' through the cross section at 938 RPS, by sequentially shifting the electrical position of the plates.

The averaged capacitance value produces a signal proportional to the volume fraction of one-phase. This signal is indicated by a meter reading, as well as a 0 – 10 volt output signal. A 'Zero' control is provided for nulling of the capacitance of the phase with the lower dielectric constant. A 'Span' control is provided for scale adjustment, due to the capacitance of the phase with the higher dielectric constant.



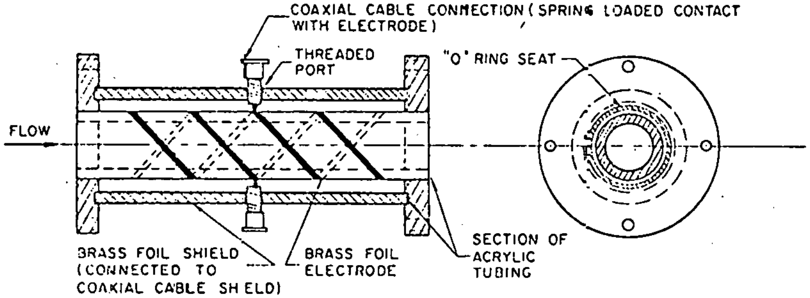


FIELD ROTATION

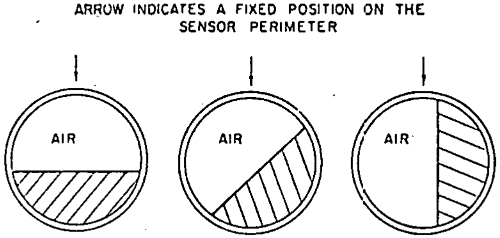
Specifications:

Power:	115 or 220 VAC 50/60 Hz
Excitation:	0-20 VPP, 30 KHz
Field Rotation Rate:	938 RPS
Dielectric Constant (ϵ) Range:	$\epsilon > 1$
Signal Output (% higher ϵ Range):	0-10 VDC @ 1 mAmp
Dimensions (Electronics):	17" wide x 5¼" high x 12" deep (Mountable in 19" rack)
Sensor:	Pressure and Temperature + Dimensions on request.

Fig. 20



— Schematic illustration of the Proposed Capacitance-Type *In-Situ* Liquid Volume Fraction Sensor.



— Effective Liquid Distribution Changes on Rotating the Sensor.

Fig. 21

RADIOISOTOPE TECHNIQUES FOR COAL CLEANING PROCESSES

S. K. Kawatra and D. M. Larsen
Department of Metallurgical Engineering
Michigan Technological University
Houghton, Michigan 49931

1. ABSTRACT

A method for on-line analysis of coal ash is being developed at the Department of Metallurgical Engineering of Michigan Technological University. A test unit is being constructed which incorporates two radioisotope sources and radiation detectors. The test unit is easily portable and designed for use in a rugged environment. This paper describes the theory and development of the system in detail.

2. INTRODUCTION

Recent increased interest in coal production has brought about incentive to automate coal processing plants. Such work is generally motivated by economic gains resulting from increased recovery and quality of coal.

Maintaining optimum conditions in a coal processing plant to achieve the maximum recovery and quality desired is often extremely difficult, as variations in feed and operation of the plant dictate minute to minute manipulation of many operating variables. It is imperative that the response of the product stream to such manipulations be known. The most effective means of obtaining important operating information is through on-line analysis.

Measurement of ash content in coal is an important factor in quality control. The development of an instrument for on-line measurement of ash content would aid tremendously in improving plant performance, such as, utilizing the signal from the coal ash sensor to control reagent additions in the flotation circuit.

Development of such an instrument for analysis of coal slurries cannot be considered apart from the operating conditions or process to which it will be subjected. Keeping this point in mind, the experimental work required for development can be

(i) Evaluation of the process
(ii) Development of radiometric techniques, and
(iii) Testing of the equipment under plant conditions.

3. PROCESS EVALUATION

Initially a feasibility study to evaluate the process would entail the collection of data from a coal concentrating plant. Critical information derived from operating data would include:

(1) the range of percentage of solids,
(2) the chemical composition of the solids, indicating what matrix is associated with the solids, and to what extent the matrix can vary under different operating conditions, and
(3) the particle size distribution in various streams which would suggest whether or not an additional grinding loop would be required with the radiometric instrument.

A basic flowsheet representing a typical coal preparation plant is shown in Figure 1.

4. DEVELOPMENT OF RADIOMETRIC TECHNIQUES

Determination of ash content of coal in slurries involves making two measurements (1-4):

(a) Percentage of solids in the slurry
(b) Ash content of the coal slurry.

Thus, two gauges must be employed; the output of one being proportional to the percentage of solids in the slurry and that of the other to the ash content of the slurry. The percentages of solids can be determined by a gamma transmission gauge which is designed on principles which are now well established (1-4).

5. METHODS OF DETERMINING ASH CONTENT IN SOLIDS

Ash content in the slurry can be measured by one of the techniques described below:

(a) Beta particle backscatter (5,6):

The intensity of beta particles backscattered from a material increases with increasing mean atomic number of the material. In the case of coal, the mean atomic number increases with increasing ash content. The intensity, I_s, of beta particles scattered back from saturation thickness of a material of atomic number, $\bar{Z}$, is approximately proportional to $\bar{Z}^{0.5}$, where $\bar{Z}$ is the effective atomic number of the material and is given by

$$\bar{Z} = \Sigma \gamma_i Z_i$$

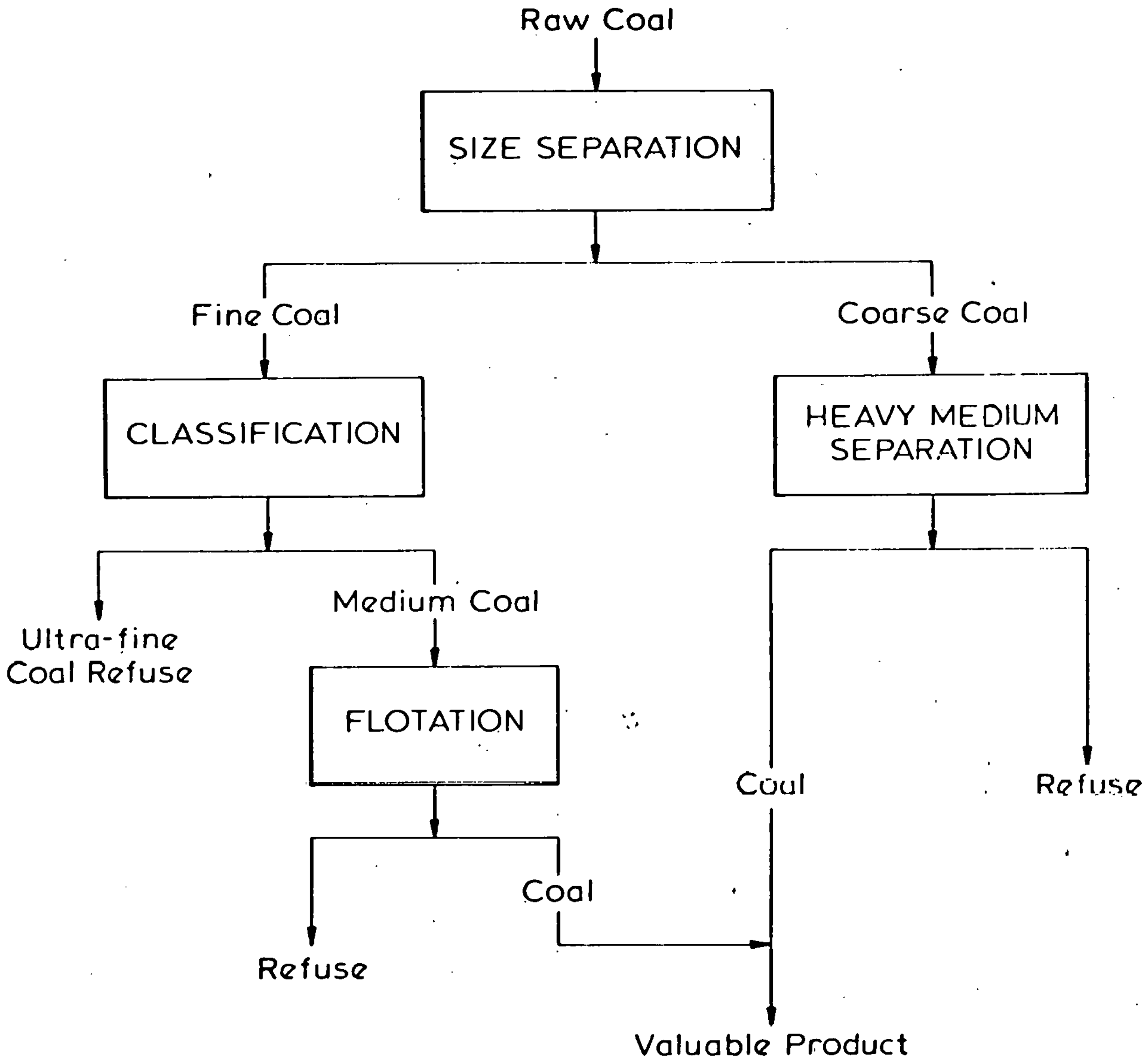


Figure 1. The basic flow sheet of a coal preparation plant.

where γ_i is the weight fraction of the element with atomic number Z_i.

Normally, $\bar{Z}(\text{coal}) \simeq 6$ and $\bar{Z}(\text{ash}) \simeq 12$.

Thus,

$$\frac{I_s(\text{ash})}{I_s(\text{coal})} = 1.4$$

Therefore, the change in I_s from zero to one hundred percent ash is approximately 40%. At 10% ash, the relative sensitivity to ash (that is, the percentage change in backscattered intensity for a 1% relative change in ash content) is approximately 0.04. This can be measured accurately.

The main advantage of this technique lies in its simplicity. The technique does not incorporate the use of any sophisticated electronic equipment. However, if there are large variations in the iron content of the ash, this method is not highly accurate as there is no known simple way of correcting for iron variations resulting from backscattering of beta particles.

A schematic diagram of the system is shown in Figure 2.

(b) Transmission of electromagnetic radiation

The intensity of electromagnetic radiation transmitted through a material of fixed surface density (mass/area) decreases with increasing mass attenuation coefficient of the bulk material.

At energies less than 100 KeV, the mass attenuation coefficient changes rapidly with atomic number, and hence, the transmitted intensity is sensitive to the ash content of coal. By similar calculation, (as for backscattering of beta particles) it can be shown that a very high sensitivity can be obtained with a transmission system. This method is expected to be more sensitive than the beta scattering method. The transmission system also allows correction for iron variations in the ash. For instance, suppose an Fe-55 source is selected. This source emits 6.0 KeV MnK radiation. At this energy, the mass absorption coefficient of iron is equal to that of the rest of the ash. Hence, variations in the iron content can be corrected.

However, a transmission technique is more sensitive to air content of a slurry than a backscattering technique. It also does not correct for variation of sulphur, chlorine and calcium in the ash, although much of the time the errors introduced by variation of these elements are within acceptable precision.

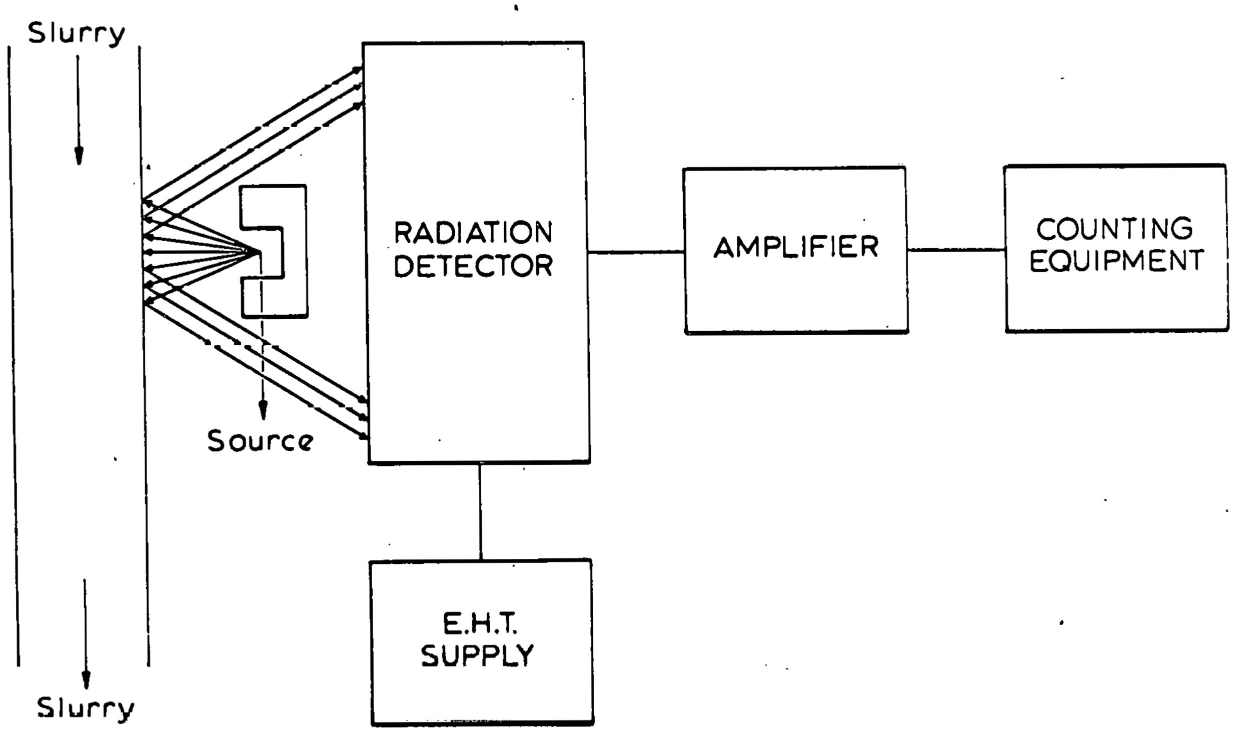


Figure 2. Schematic diagram of a backscattered type of gauge.

A schematic diagram is shown in Figure 3.

(c) Backscatter of electromagnetic radiation

The intensity of electromagnetic radiation backscattered from a sample is proportional to the scattering mass attenuation coefficient of the sample divided by the total mass attenuation coefficient. The magnitude of the total mass attenuation coefficient is a function of the average atomic number of the sample and the energy of the incident radiation. Thus the scattered intenstiy increases and becomes increasingly more sensitive to coal ash as the energy of the radiation is decreased from 100 to 20 KeV. Pu-238 or Cd-109 sources with x-ray energies of 12-21 KeV and 22 KeV respectively are quite suitable for this purpose. Both of these sources can be used to produce FeK fluorescent x-rays if large variations of iron content occur. The intensity of the FeK x-rays produced can be used for a correction of large variations of iron content in the coal.

Slurry streams in most modern coal processing plant contain considerable amounts of entrained air bubbles. The coal itself may contain large variations in iron content. Hence for the analysis of coal slurry streams, the technique of using backscattered electromagnetic radiation is most suitable. Backscatter techniques have the advantage over transmission techniques of not being affected by air bubble content. Also, the beta particle backscatter technique would require an additional radioisotope source to allow for the correction of iron content in the slurry. Using the backscattered electromagnetic radiation technique this additional sensor is not required. FeK fluorescent x-rays will be produced and detected directly by the ash sensor.

6. DESIGN OF EXPERIMENTAL APPARATUS

A Gd-153 gamma-ray source and a scintillation detector make up the slurry density gauge. A 40 m Ci. Cd-109 source (22 KeV) and a Xenon filled proportional counter compose the ash sensor. The Cd-109 source is set at a 45° angle to a 0.5 mil. polypropylene window in the ash flow cell. The backscattered radiation normal to the window enters the proportional counter. The signal from the proportional counter is sent to a MCA. The result is printed out on a Tl-700 silent terminal.

The test rig (Figure 4) incorporates a centrifugal pump feeding the slurry to a constant pressure head tank. The coal slurry gravity feeds the

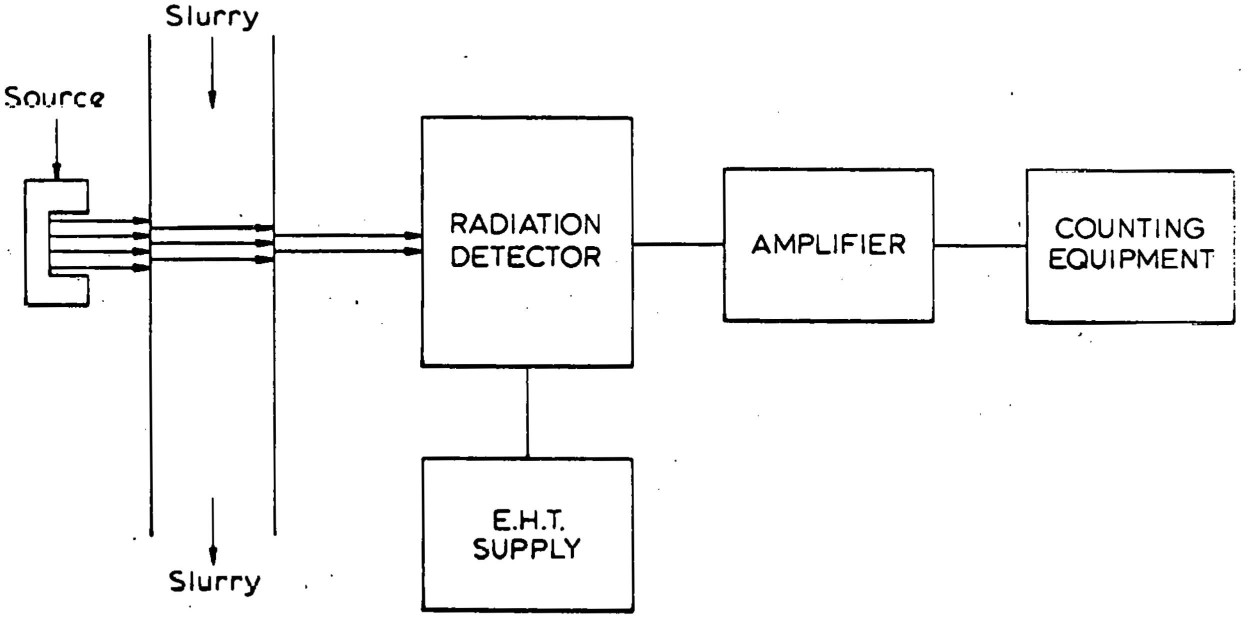


Figure 3. Schematic diagram of a transmission type of gauge.

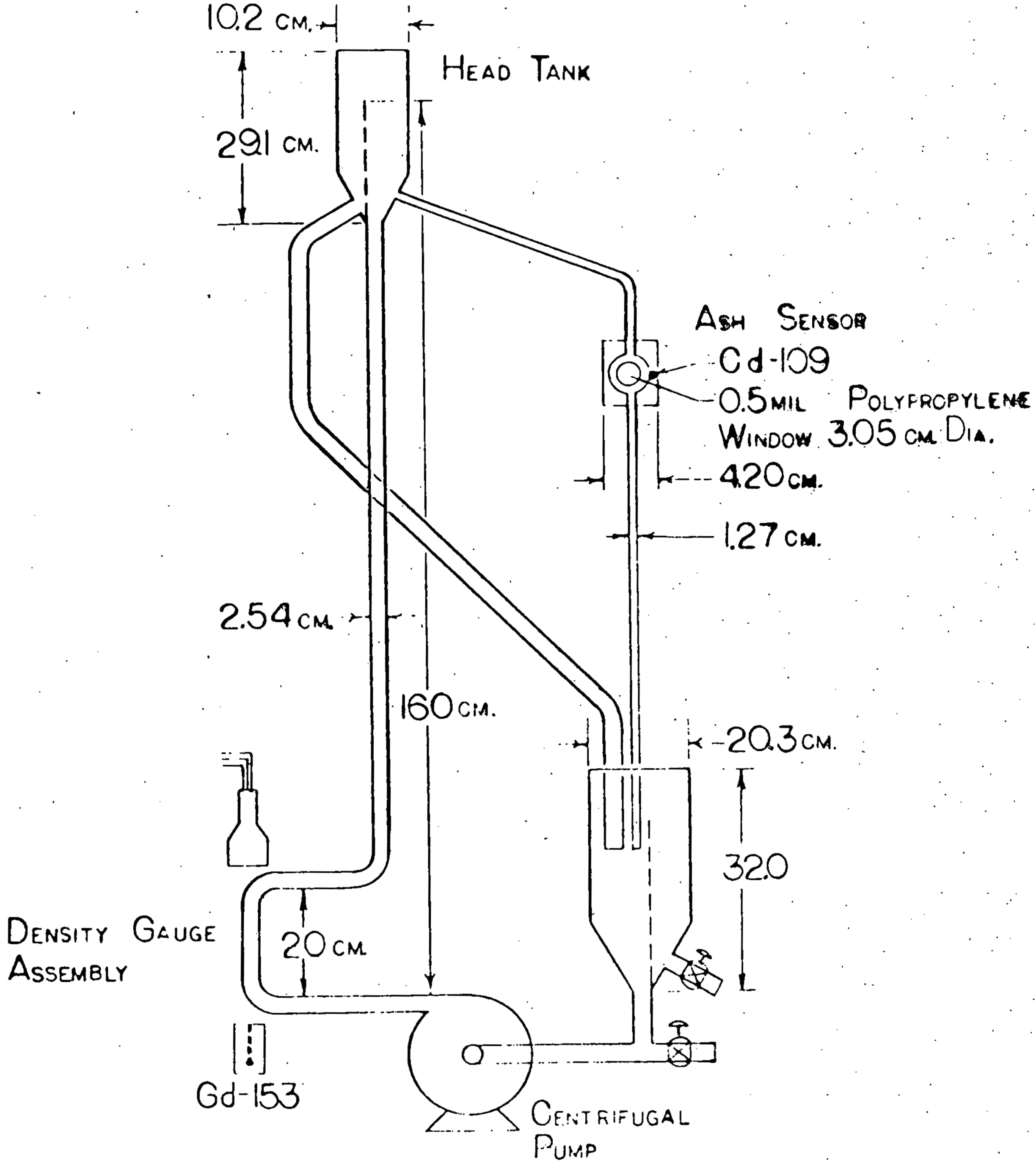


Figure 4. Schematic diagram of the test rig.

ash sensor flow cell. All products are collected in a common sump for recirculation by the pump. The system is designed to use a recirculating coal sample or accept plant feed and operate on an in-line basis. The entire test apparatus is mounted on a wood base and frame with casters for easy transportation and setup.

The combined information from the ash sensor and the density gauge can be fed into an appropriate equation to yield the percent ash by weight in the coal. An additional correction for variable iron content can also be incorporated into the equation. This correction will be based on the intensity of FeK fluorescent x-rays obtained directly from the ash sensor-MCA system.

7. CONCLUSION

A method for on-line analysis of coal ash is being developed which uses two radiometric sensors; a density gauge and an ash sensor. The density gauge operates on principles already well established. The operation of the ash sensor is based on the electromagnetic radiation from a radioisotope backscattered by a coal slurry sample. These units are incorporated into a test rig designed to tolerate the abusive environment of a mineral processing plant. The test rig can be easily transported to various plant sites for on-line operational testwork.

8. ACKNOWLEDGEMENTS

The financial support provided by the Department of Energy (Grant No. ET-78-G-01-3317) is gratefully acknowledged.

9. REFERENCES

1. Kawatra, S. K., "Effects of Variation of Entrained Air in Flotation Slurries on the On-Stream Determination of Copper by Radioisotope X-ray Fluorescent Analysis", Canadian Journal of Spectroscopy, Vol. 21, No. 1, 1976.
2. Kawatra, S. K., "The Design and Operational Characteristics of a Portable Multi-Stream On-Line Analyzer", International Journal of Mineral Processing, Vol. 3, No. 1, 1976.
3. Kawatra, S. K., "The On-Line Measurement of Ash in Coal Slurries", Canadian Journal of Spectroscopy, Vol. 21, No. 2, 1976.
4. Kawatra, S. K., "The Influence of Length of Flow Cell and Strength of a Source on the Performance of a Gamma Density Gauge", International Journal of Mineral Processing, Vol. 3, No. 2, 1976.

5. Clayton, C. G., "Recent Developments and Applications of Nuclear Techniques in the Exploitation of Mineral Resources", Conference on the Technological Applications of Nuclear Techniques, Pelindaba, 1972.

6. Clayton, C. G. and Cameron, J. F., "A Review of the Design and Applications of Radioisotope Instruments in Industry", Proceedings of the Symposium on Radioisotope Instruments in Industry and Geophysics, Vol. 1, International Atomic Energy Agency, Vienna.

ADVANCED TECHNIQUES AND INSTRUMENTATION FOR REAL TIME ON-LINE AND LABORATORY ANALYSIS OF COAL

T. Gozani, H. Bozorgmanesh, D. R. Brown, B. Director, E. Elias
Science Applications, Incorporated, Palo Alto, California

O. J. Tassicker
Electric Power Research Institute, Palo Alto, California

R. Bevan
McNally/Kennedy Van Saun Corporation, Danville, PA

ABSTRACT

Methods for on (and off) line nondestructive composition analysis of coal are described. Nuclear methods based on prompt neutron activation analysis have been extensively developed for rapid on-line process control in an industrial environment. Several instruments were developed to perform on-line elemental analysis of coal in fossil burning power plant or coal mines. Results are generally in good agreement with the more elaborate standard ASTM analytical methods when the sampling errors in the latter are minimized. Non-invasive methods based on capacitive and microwave interrogation have been successfully demonstrated for moisture determination in coal. Application of high energy neutron activation analysis method is recommended for rapid determination of the oxygen content and other difficult to determine elements such as magnesium in coal.

INTRODUCTION

The need to accelerate and expand the utilization of coal has been broadly recognized in the last few years. In parallel, an extensive effort has been made to develop rapid and non-invasive techniques for measuring coal composition and quality. Of particular significance is the development of advanced methods for on-line compositional analysis of the entire process stream. These techniques are highly suitable for process control since they eliminate the need for elaborate sampling and sample preparation procedures required in all standard methods for coal analysis.

Since 1976 the coal instrumentation group of the Advanced Nucleonics Division, under sponsorship of the Electric Power Research Institute (EPRI), Science Applications, Inc. (SAI) and Kennedy Van Saun Corporation (of the McNally Pittsburg group) is evaluating, developing and manufacturing various instruments for rapid nondestructive assay of coal. Applications include continuous coal measurements for monitoring mining, power plants operation, coal preparation and specific boiler operations for slagging and fouling control. The following areas are covered.

a. Complete elemental analysis
b. Moisture measurement
c. Sulfur determination
d. Ash analysis
e. Btu content determination
f. Oxygen measurement

This paper presents some of the recent instrumentation developments for coal analysis. The basic principles and systems design criteria are briefly discussed.

CONTINUOUS ON-LINE NUCLEAR ASSAY OF COAL (CONAC)

Application of nuclear techniques based on prompt neutron activation analysis (PNAA) for coal elemental analysis offer the possibility of noninvasive, continuous, on-line monitoring of process streams. The principle of PNAA of coal have been discussed extensively in the literature Ref. (1-10). Briefly a source of fast neutrons is placed near or inside a mass of coal. A large fraction of the fast neutrons are slowed down to thermal energies and are captured by the nuclei of the various constituents of coal. The probability of neutron capture by a specific constituent depends on its capture cross-section and weight percent. In coal measurement between 80 to 95% of all absorption occur in the nuclei of hydrogen. The absorption in sulfur constitutes between 0.1% for low sulfur coal and up to 3% of the total absorption for high sulfur coal. The nuclei that captured the neutron emit, within every short time ($<10^{-9}$ sec), characteristic gamma rays which provide quantitative "signatures" of the various constituents. Most of these characteristic gamma rays have high energy and can readily penetrate the mass of coal. A gamma ray detector is placed outside the coal and detects the gamma rays. The relative amount of the coal constituent is determined from the detected specific gamma rays. The ability of the detector to distinguish between the multitude of lines is called resolution. Examples of high resolution detectors are Ge(Li) and hyper-pure Ge, a medium resolution detector is NaI(Tℓ) and low resolution detector is the plastic scintillator. Typically a high resolution detector is used in the CONAC system for multi-element analysis. If only the sulfur and a few other major elements in coal are desired, NaI(Tℓ) can be used.

During the past three years, SAI, in close contact with a number of large utilities, has done an extensive investigation using both Ge and NaI detectors to determine optimum configuration for PNAA of coal for use with the CONAC system. Optimization of accuracy and reproducability involves consideration of neutron and gamma ray interactions in the coal, coal rheological properties and also methods of coal conveyance.

A conceptual design of a CONAC installation is shown in Figure 1. Various types of coal with widely varying compositions have been analyzed with a laboratory CONAC system. These include coal from high to low rank with low, medium and high sulfur and ash contents and with tope size between less than -1/4 in.(0.6 cm) to less than -3 in.(7.5 cm). Figure 2 illustrates a typical neutron-induced gamma ray spectrum measured for a sample of Pittsburg #8 coal using a high resolution Ge(Li) detector. As seen, the spectrum contains a profusion of closely spaced spectral lines. Obviously high resolution detector and an advanced software are required for analyzing such a spectrum to determine the elemental composition of the sample. Gamma spectra from various coal types and blends have been analyzed to assess the accuracy of the CONAC system. The results were compared with standard ASTM chemical analysis carried out by several laboratories. Generally the CONAC results were more accurate than that obtained from ASTM analytical and sampling methods. Table 1 shows the error spread for four elements (H, S, C, and Cℓ) obtained in seven different coal samples by the CONAC system and by ASTM methods. The Pittsburgh coal sample was selected as a standard in this analysis, since the spread between the various ASTM results for this coal was small enough and deemed acceptable.

A laboratory version of the CONAC system has been built and tested at SAI. It enables rapid elemental analysis of a large sample (75-100 Kg) of coal. Figure 3 shows the major components of the system. A Ge(Li) detector is used for the complete elemental analysis of the sample. A computerized analyzer and state-of-the-art electronics (Figure 4) are used to process the gamma signa-

TABLE 1

Concentration Of Some Elements In Various Types Of Coal As Determined By CONAC And Conventional ASTM Techniques

ANALYSIS ("As Received" Basis)								
COAL TYPE	HYDROGEN		SULFUR		CARBON		CHLORINE	
	PNAA†	ASTM*	PNAA†	ASTM*	PNAA†	ASTM*	PNAA†	ASTM*
E.Ohio(1¼)	5.11 ± .02	5.02 ± 0.11	2.91 ± .02	2.91 ± .13	68.65 ± .9	68.7 ± 1.3	0.128 ± .002	0.086
DEK	6.44 ± .02	5.23 ± 0.99	0.38 ± .01	0.39 ± .07	56.36 ± .7	60.5 ± 5.2	0.0038± .0006	0.018
E.KEN	5.62 ± .02	4.93 ± 0.19	0.90 ± .01	0.82 ± .04	69.11 ± .9	67.8 ± .1	0.039 ± .001	0.037
Blend 1	5.74 ± .02	5.52 ± 0.64	1.25 ± .01	1.28 ± .17	68.77 ± .8	67.8 ± 4.4	0.051 ± .001	0.042 ± .018
Blend 2	6.03 ± .02	5.63 ± 0.98	1.34 ± .01	1.21 ± .09	65.16 ± .8	64.9 ± 4.4	0.050 ± .001	0.086 ± 0.034
NM (¼)	4.78 ± .02	4.70 ± 0.53	0.93 ± .01	0.94 ± .03	51.50 ± .7	55.8 ± 4.0	0.066 ± .001	0.082
PITTS.**	5.13 ± .02	5.13 ± 0.07	2.91 ± .02	2.91 ± .03	71.40 ± .9	71.4 ± .7	0.144 ± .001	0.144 ± 0.023

†PNAA uncertainties in analysis PNAA = Prompt Neutron Activation Analysis

*ASTM uncertainties based on deviations between 2 or 3 laboratory results. With Chlorine where no uncertainties are quoted, only one laboratory submitted results.

**PNAA results are normalized to ASTM results for PITTS #8 coal. This establishes the absolute calibration of the PNAA results for these measurements.

tures for determining the elemental composition of the sample. The system is calibrated routinely using known reference samples of coal. Careful preparation of the reference samples involves determining the bulk density and mapping of their density distribution by gamma transmission techniques. This information is then used for a small density correction.

The CONAC system can be easily integrated in the overall coal conveying system of a plant. It can be designed to handle 1%, 10% or even 100% of the coal flow in a typical process stream. However, if it is necessary to measure a large fraction of the coal throughput, multiple neutron sources and detectors may be required across the belt since one source/detector combination only interrogates a strip of coal approximately 2 ft. (61 cm) wide. The speed of the belt for the prototype system is designed to vary so as to present between 1 and 50 tons of coal per hour for analysis. Figure 5 shows one possible conceptual arrangement for integrating the CONAC into a coal-fired power plant. Diversion of the coal is accomplished by cutting a primary stream of coal to the plant and sending a stream of coal to the analysis section located in a sample house. Following the analysis, the coal can be routed back into the main stream. All CONAC components lend themselves to field use. In an actual installation the operator is provided with basic data such as weight percent of the significant constituents in the coal. In addition information on the status of the equipment and its radiation and mechanical safety interlocks are available. This data could be further processed to give the operator more information on the coal that will be used to generate power within hours. Such information could be in the form of fouling and slagging indices, Btu value, hourly and daily averages of sulfur and moisture content, etc. The specific form of the processed information can be modified to suit the specific utility needs as experience is gained. Quality and process control in coal mines can also be achieved by proper location of the CONAC in the flow materials stream and proper utilization of the data it generates.

HYDROGEN AND MOISTURE MEASUREMENT

Hydrogen appears in coal in two different forms: moisture and volatile matter. Both are normally determined using standard ASTM analytical-chemical techniques. These techniques, however, are time consuming and require a major effort in obtaining and processing a small (gram size) representative sample from a flow of tens to hundreds tons of coal per hour. A rapid method to measure the total hydrogen of coal when used in conjunction with a continuous moisture meter could provide a detailed information on the volatile matter content and on the Btu value of the coal.

During the past several years, we have been investigating various nuclear and non-nuclear techniques for hydrogen and moisture determination in coal. Critical review of the available methods and recomendations for a continuous on-line measurement are summarized in Ref. (11) to (13). It has been shown that among the possible nuclear techniques for total hydrogen determination a system based on measuring the leakage of epithermal neutrons provides the best indication of hydrogen density, with the least dependence on coal composition. Using that method, the total hydrogen density in coal is measured with an average absolute error of 1.8 x 10^{-3} g/cm^3. The system response is shown in Figure 6 as a function of the hydrogen density (wt. % hydrogen x bulk density). Results are shown for various types of coal representing a wide range of compositions and bulk densities expected in practice.

Two electromagnetic techniques: capacitance and microwave absorption, have been investigated for on-line moisture monitoring of coal. The response of instruments based on these techniques was measured using a representative range of U.S. coal types and moisture levels. Figure 7 illustrates three basic capacitor geometries investigated for on-line applications: the cylindrical chute, the parallel plate pass-through and the parallel plate ski. The parallel plate pass-through configuration has been found most attractive for on-line application since the plate could be placed on either side of a conveyor belt. The system consists basically of two flat rectangular plates with area of 750 cm^2 (0.81 $ft.^2$). The plates are spaced 22 cm (0.72 ft.) apart and can interrogate as much as 30 lbs. (13.3 Kg) of coal. Other configurations are also being investigated.

Figure 8 shows the basic setup for the microwave attenuation measurement for coal. A differential frequency measurement and analysis technique Ref. (14), was used to reduce the measurement sensitivity to coal type and instrumental effects. Figure 9 shows a laboratory version of the microwave moisture meter. Typical response of the microwave method is shown in Figure 10 for various frequencies and moisture levels. A single response curve for various coal types are illustrated in Figure 11. Uncertainties in moisture determination of less than 5 percent relative (typically ±0.6 wt.% absolute) were obtained employing our measurement systems. In on-line applications, this level of accuracy in moisture determination, combined with the accuracy in measuring other elemental content with a CONAC system, will allow the coal Btu value to be deduced with accuracies of 2 percent or better.

SULFUR DETERMINATION

The coal sulfur content restricts its use and thus its value as an energy source. Too much sulfur prevents direct combustion and necessitates special expensive pre-combustion (e.g. cleaning or blending) and for post-combustion (e.g. scrubbers) treatment. Sulfur can be measured very accurately by prompt neutron activation analysis using a high resolution Ge(Li) detector. Results of such measurement were obtained by our laboratory version of the CONAC system and are summarized in Table 1. Because of the low efficiency of Ge(Li) detectors, a relatively long measurement (about 1000 sec.) is typically necessary to obtain sufficiently precise results. Sodium iodide NaI(Tℓ) detectons are much more efficient (by a factor of 10 to 100) than the Ge detector allowing much rapid measurement. They are, however, less stable and their energy resolution is poorer than the Ge(Li) detectors as shown in Figure 12. This figure shows the spectrum measured by NaI(Tℓ) detector of the same coal whose spectrum is shown in Figure 2. Except for hydrogen, each peak shown in the NaI spectrum contains contributions from several constituents making direct determination of individual elements more difficult. However, in the case of sulfur, the contribution of the sulfur line to the peak labeled "S" is dominant allowing direct determination of sulfur weight percent if proper account of the other contributing elements, e.g., iron, nitrogen, chlorine, and others, is taken. A special Spectral Correlation Method (SCM) has been developed by SAI which yields reliable sulfur reading over a wide range of coal types. The method accounts for the contributions to the sulfur peak from most of the interfering elements. This is accomplished by establishing a correlation between the contribution of the interfering element's gamma lines to the sulfur peak by measuring its contribution to a peak in some other region of the spectra.

The SCM method was used to analyze the sulfur line obtained with NaI(Tℓ) detector for a wide range of coal compositions as shown in Figure 13. The relative RMS deviation calculated from the points in Figure 13 is 2% (0.02% absolute for 1% S-coal). It should be emphasized that the coals analyzed here span the range of U.S. coal types and encompass a much wider range of compositional variations than would be normally expected for a specific coal-burning power plant. With the flexibility designed into the SAI sulfurmeter, further tailoring of the software analysis program for the range of coal used by a specific user may allow a further increase in achievable accuracy. Other elemental constituents that can be reliably extracted from the NaI spectrum using the same SCM technique are hydrogen, nitrogen, chlorine, and iron as shown in Figures 14 through 17.

A schematic of an industrial sulfur meter based on prompt neutron activation analysis is illustrated in Figure 18. The system shown in this figure is basically designed to analyze coal contained temporarily or slowly moving in a chute. This geometry was selected by a utility because of space limitations. Other geometries such as the belt configuration described before (e.g. Fig. 1) are obviously possible and generally recommended. The system consists of the following subassemblies:

- Shielded NaI(Tℓ) detector subsystem for detecting the gamma rays emitted from elements in the coal.
- ^{252}Cf neutron source and containment system with its associated biological shielding. The initial source intensity allows 5 years of operation without replacing the source. Various engineered safety features are incorporated in the source subassembly to assure safe operation in an industrial environment.
- Moderator/Reflector source assembly to enable optimum neutron flux within the coal.
- Analog and digital electronics systems to be located near the sulfurmeter and/or in the control room.

Provisions are incorporated to expand the system capability for measuring other coal constituents besides sulfur and other important quantities such as coal calorific value, and mineral matter ("ash").

OXYGEN DETERMINATION

Oxygen accounts for about 5 to 20 weight percent of various raw coals. Obviously accurate determination of oxygen in coal process streams is important for mass balance considerations in ultimate analysis and process control. Determination of oxygen in coal provides basically a complete elemental composition of coal without recourse to indirect determination by "by-difference" as is currently done. Oxygen has a very low thermal neutron capture cross section, making it impossible to determine its weight percent by interrogating the coal with thermalized neutrons from a ^{252}Cf source. However, oxygen has a relatively high cross section for inelastic scattering of high energy neutrons leading to gamma production of $\sim$ 6 MeV. Further, neutrons above 10 MeV produce 6.1 MeV gammas via the $^{16}O(n,p)^{16}N$ reaction (40 mb cross section). The ^{16}N decays with a half-life of 7.1 sec and can be detected by conventional delayed activation techniques. Fast neutron interrogation provides, therefore, a feasible way of oxygen determination in coal. The spectrum of Pittsburg #8 coal irradiated repeatedly with short bursts of 14 MeV neutrons as measured with NaI detector is shown in Figure 19.

Fast neutrons activation can also be used for determining other difficult to measure elements in coal besides oxygen. For instance, Mg has a relatively high cross section for $^{24}Mg(n,p)^{24}Na$ reaction at high neutron energies (200 mb at 14 MeV). The radioactive reaction's product, ^{24}Na has 15 hr. half life which enable a convenient measurement of its activity after irradiation far from the neutron source. The same isotope, ^{24}Na is also a product of $^{27}Al(n,\alpha)^{24}Na$ reaction which may take place at high neutron energies (120 mb at 14 MeV). Therefore, a correction procedure using a combination of thermal and fast neutron activation techniques has to be used to deduce separately the weight percent of ^{27}Al and ^{24}Mg. Fast neutron activation techniques may also be used for measuring Na, K, and P content in coal which are otherwise difficult to determine.

High energy neutron (14 MeV) are conveniently produced by a small neutron generator using $T(d,n)^{4}He$ reaction. A 14 MeV neutron generator is currently applied in the fast neutron activation analysis laboratory at SAI. Associated with this facility is a 66 in (1.68 m) activation tank which incorporates a "dry well" to enable sample handling for fast neutron activation, see e.g., Figure 20. Samples of various sizes can be analyzed at the laboratory.

SUMMARY

An extensive instrumentation development program has been outlined for coal analysis. Systems are described for various applications in the coal industry such as complete elemental analysis of coal, sulfur monitoring, ash analysis, Btu content determination, moisture determination and oxygen analysis. Nuclear methods based on PNAA (prompt neutron activation analysis) have been extensively developed for rapid on-line measurements for coal process control as well as for rapid laboratory type analysis of large samples. Both high-resolution low-efficiency Ge(Li) detectors and medium-resolution high efficiency NaI(Tℓ) detectors are applied. Ge(Li) detector is typically utilized in the CONAC (Continuous On-Line Nuclear Analyzer of Coal) system to provide a complete analysis of coal and ash composition. Systems based on NaI(Tℓ) detectors are currently used for rapid analysis of coal. Two main system configurations are typically applied; belt and chute (or bin). These geometries have been found suitable for a wide range of applications in the coal industry.

The composition and quality of a wide variety of US coal types have been measured using the SAI PNAA systems. It has been demonstrated that all important coal constituents can be measured in a continuous manner. Reliable results have been obtained for sulfur, hydrogen, carbon, nitrogen, chlorine and typical metals which are slag formers. Results have been checked against a variety of other analysis techniques including standard ASTM chemical analysis.

Non-invasive techniques based on capacitance measurement and microwave interrogation have been successfully demonstrated for determining moisture in a variety of coal types. These methods when applied with a continuous analyzer of coal composition enable a rapid and accurate on-line determination of coal calorific value.

Fast neutron activation techniques are discussed for direct measurement of oxygen and other elements such as magnesium in coal. Small neutrons generator is typically used as a fast neutron source. The system is currently applied in an off-line manner for laboratory analysis of large coal samples.

REFERENCES

1. T. Gozani, G. Reynolds, E. Elias, T. Maung, H. Bozorgmanesh and V. Orphan, "Coal Stream Composition Analysis for Process Control Using Prompt Neutron Activation Analysis", 1977 Symp. on Instrumentation and Control for Fossil Demonstration Plants, Chicago ANL-78-7, July 1977.

2. E. Elias, H. Bozorgmanesh and T. Gozani, "Determination of Total Hydrogen Content of Coal by Nuclear Techniques", ANL-78-62, 1978 Symposium on Instrumentation and Control for Fossil Demonstration Plants, Newport Beach, California, June 1978.

3. T. Gozani, "The Development of Continuous Nuclear Analyzer of Coal - A Review", ANS Trans., 28, 1978, 97.

4. T. Gozani, H. Bozorgmanesh, D. Brown, E. Elias, T. Maung and G. Reynolds, "Coal Elemental Analysis by Prompt Neutron Activation Analysis", ANS Trans., 28, 1978, 88.

5. E. Elias, H. Bozorgmanesh and T. Gozani, "An Improved Method for Determining Hydrogen Density in Coal", ANS Trans., 28, 1978, 99.

6. E. Elias, T. Gozani, V. Orphan, J. Reed and S. Shreeve, "Prompt Neutron Activation Analysis - Applications to Coal Analysis", ANS Trans. 26, 1977, 160.

7. R.F. Stewart, "Nuclear Measurements of Carbon in Bulk Materials", ISA Transactions, Vol. 6, No. 3, pp. 200-208 (1967).

8. N.C. Rasmussen, "The Potential of Prompt Activation Analysis in Industrial Processing", Analysis Instrumentation, Vol. 7, pp. 186-192 (1969), available from Instrument Society of America. Presented at the 15th AID symposium.

9. T.C. Martin, et al., "An On-Line Nuclear Analysis Facility", Interim Report No. 3, ORO 2980-12, June 1966.

10. T.C. Martin, et al., "The Application of Nuclear Techniques in Coal Analysis", Trans. Amer. Nuc. Soc., 6., pp. 181-2, (June 1963).

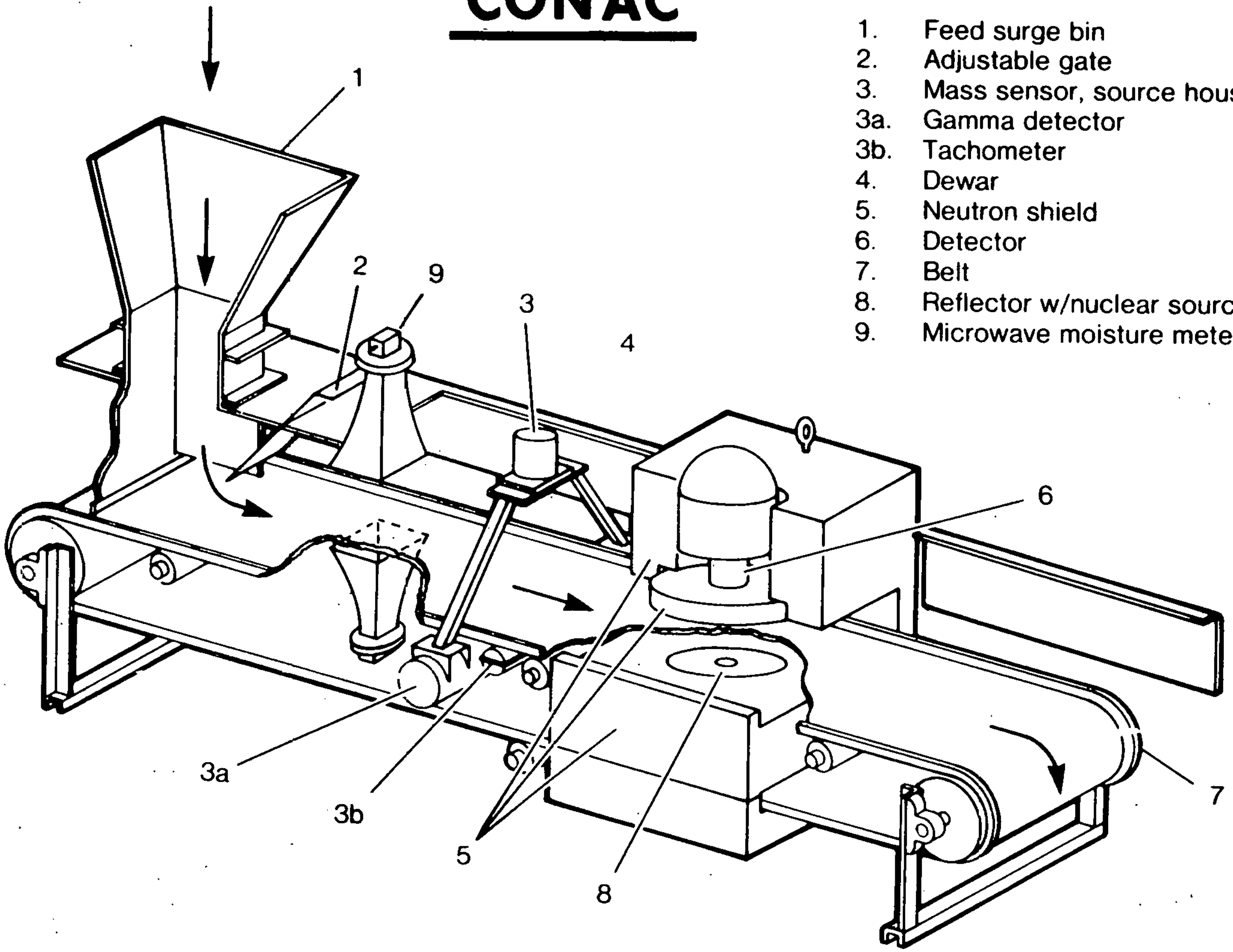
11. T. Gozani, E. Elias and H. Bozorgmanesh, "Nuclear Assay of Coal, Vol. 3- Determination of Total Hydrogen Content of Coal by Nuclear Techniques", EPRI RP-989, Jan. 1979.

12. D.R. Brown, R. Bevan, P. Luckie, H. Bozorgmanesh, E. Elias and T. Gozani, "Moisture Determination in Coal: Non Nuclear Techniques", SAI-076-77-PA Jan. 1978.

13. D.R. Brown, H. Bozorgmanesh, E. Elias and T. Gozani, "Moisture Measurement in Coal - Non-Nuclear Techniques", ANL-78-62, 1978 Symposium on Instrumentation and Control for Fossil Demonstration Plants, Newport Beach, California, June 1978.

14. D.R. Brown, "Coal Btu Measurement Study: Monitoring of Moisture in Coal" SAI-150-79-PA, April 1979.

CONAC



1. Feed surge bin
2. Adjustable gate
3. Mass sensor, source housing
3a. Gamma detector
3b. Tachometer
4. Dewar
5. Neutron shield
6. Detector
7. Belt
8. Reflector w/nuclear source
9. Microwave moisture meter

Figure 1. Schematic View of CONAC

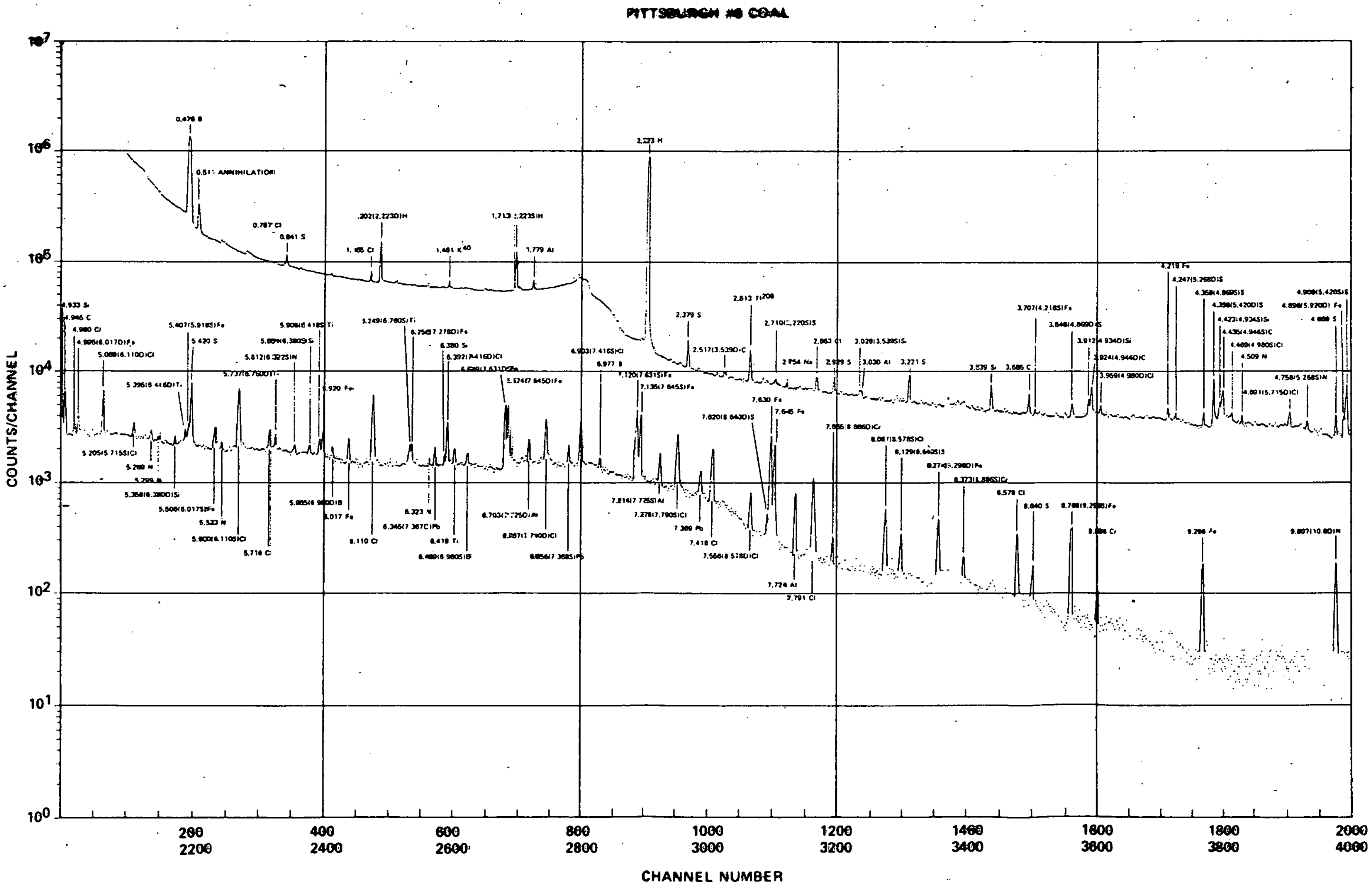


Figure 2. Ge(Li) Spectrum of Pittsburgh #8 Coal

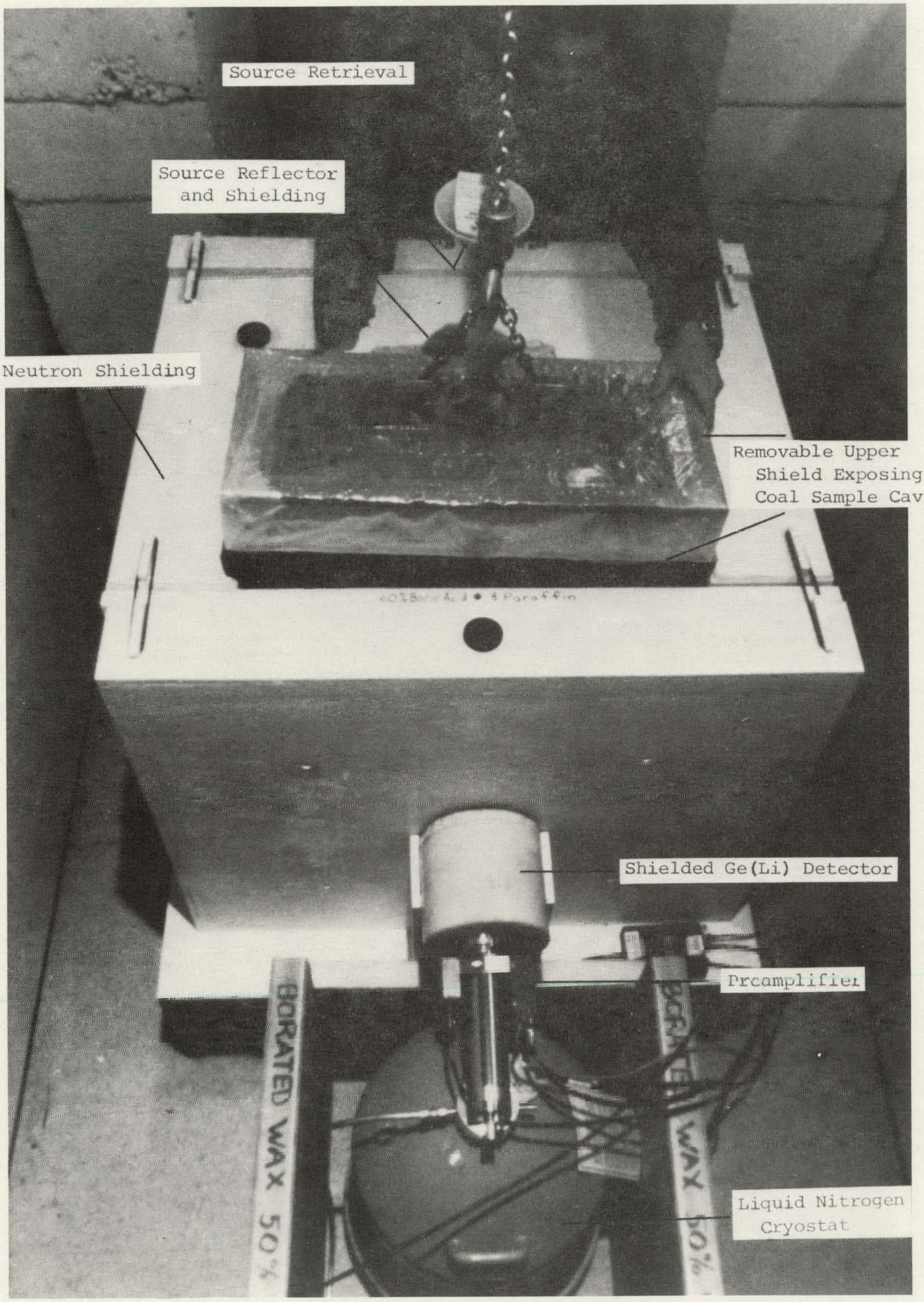


Figure 3. Photograph of Laboratory CONAC

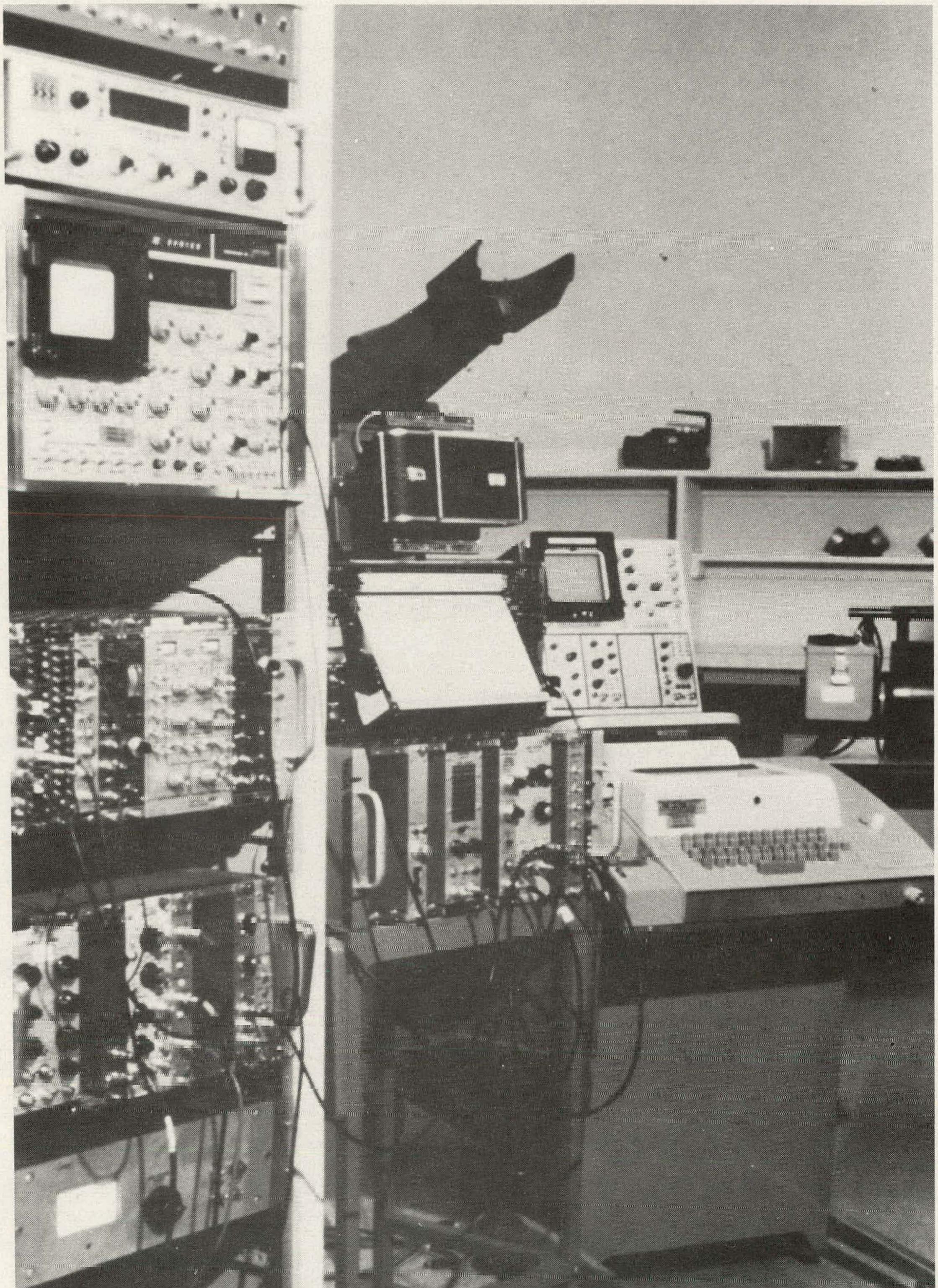


Figure 4. Photograph of Various Electronic Systems Used in Conjunction with CONAC Research

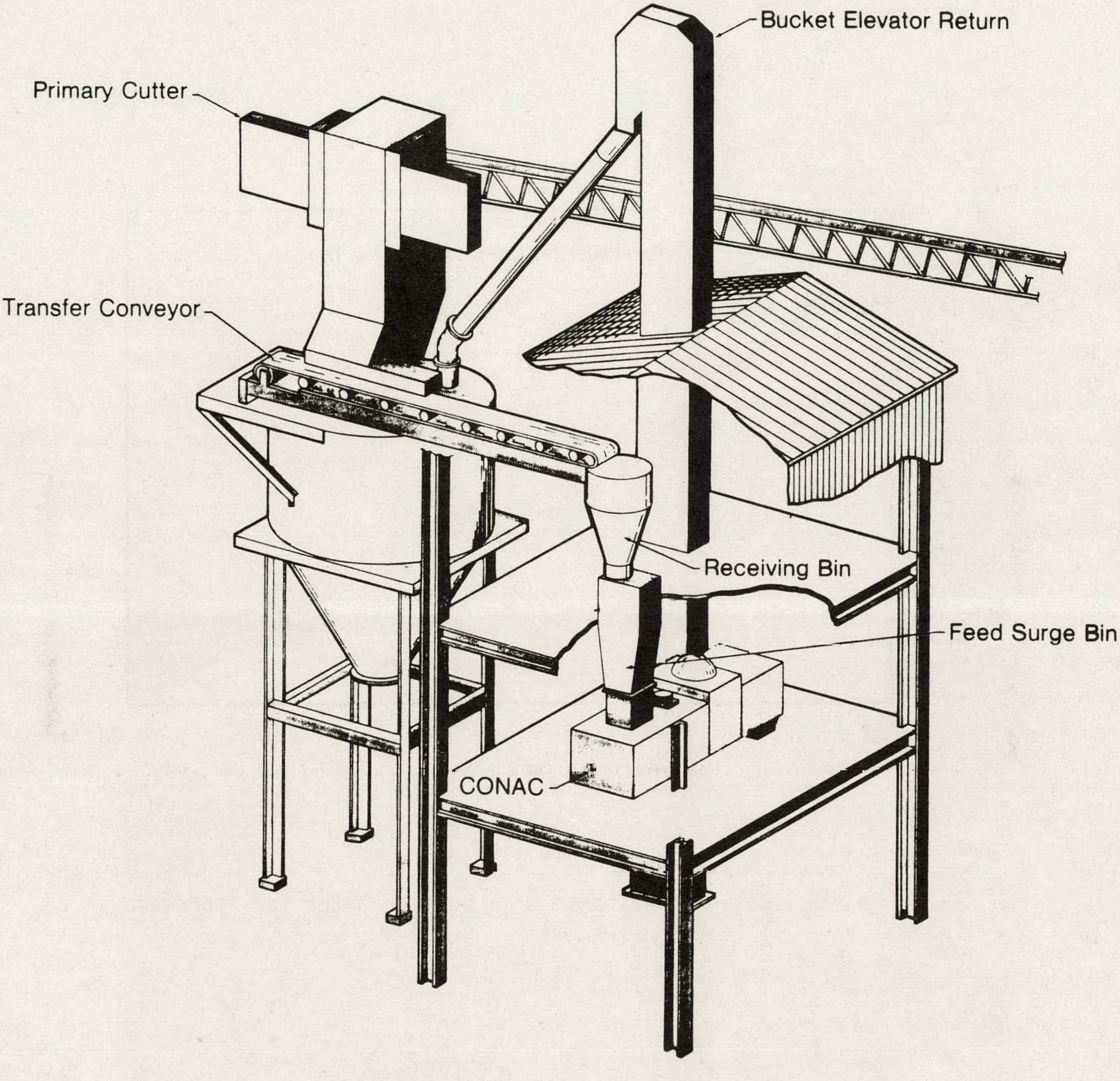


Figure 5. CONAC Integrated into a Typical Power Plant

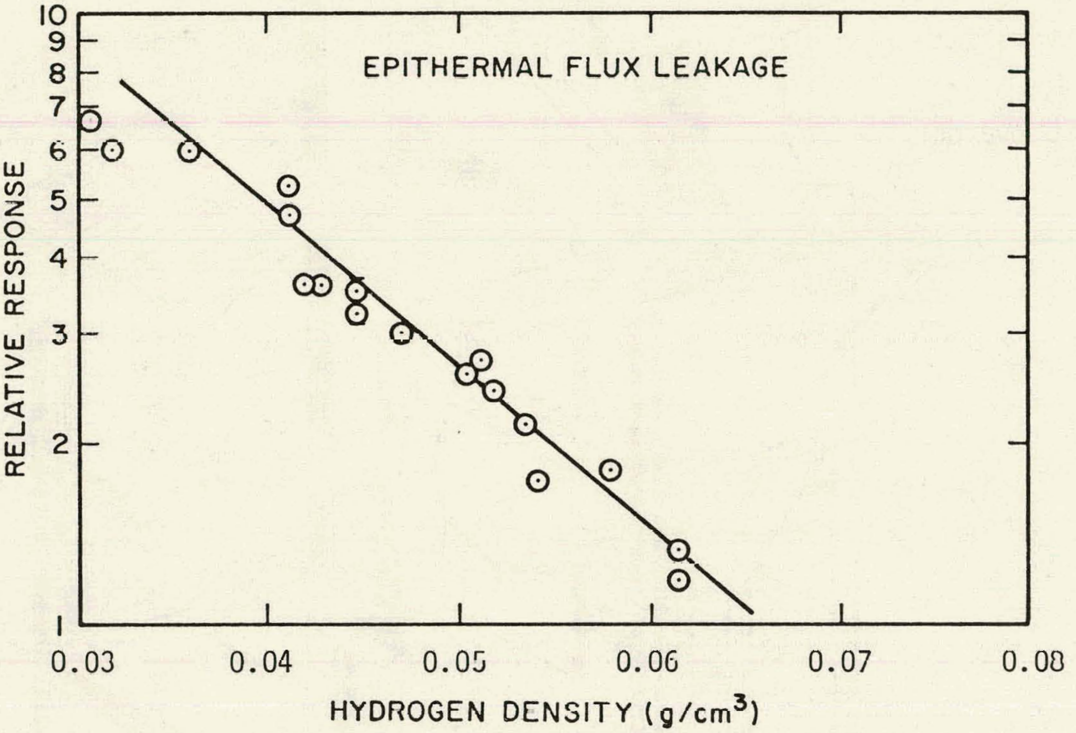
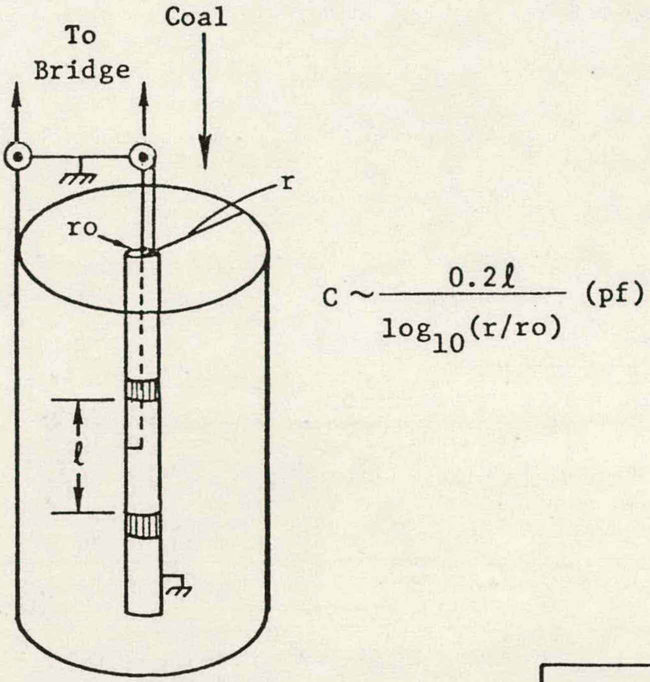
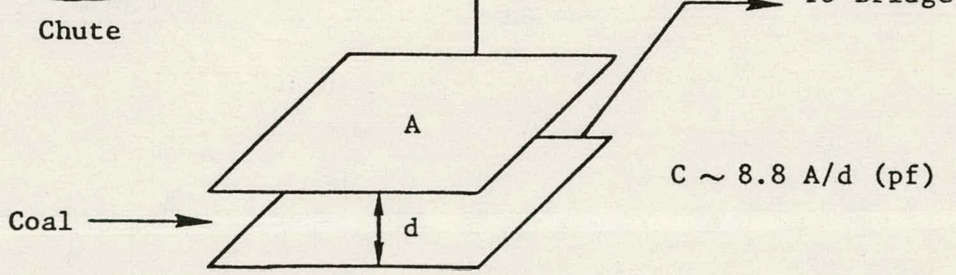


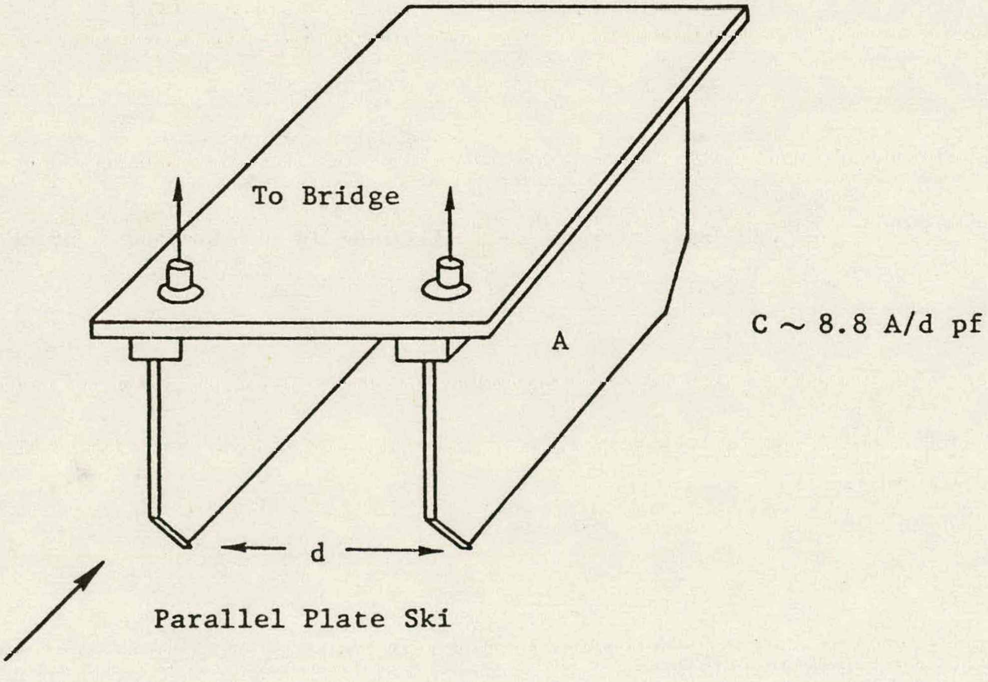
Figure 6. Relative Response of a Nuclear Meter for Hydrogen Measurement of Coal



Chute



Pass-Through Parallel Plate



Parallel Plate Ski

Figure 7. Three Capacitor Geometries Investigated. The parallel plate ski was judged to be the most suitable for on-line application.

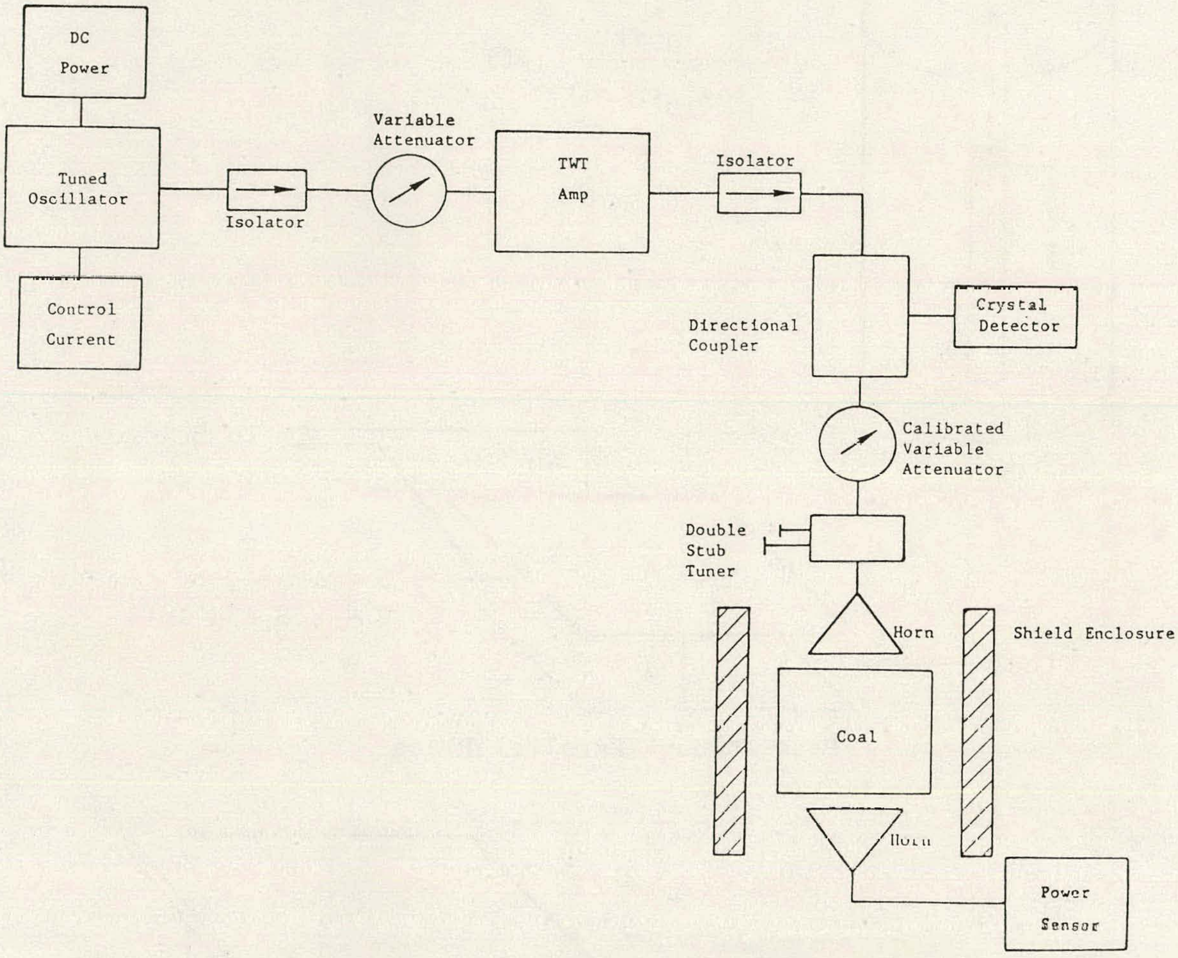


Figure 8. Microwave Attenuation Measurement Setup for Coal

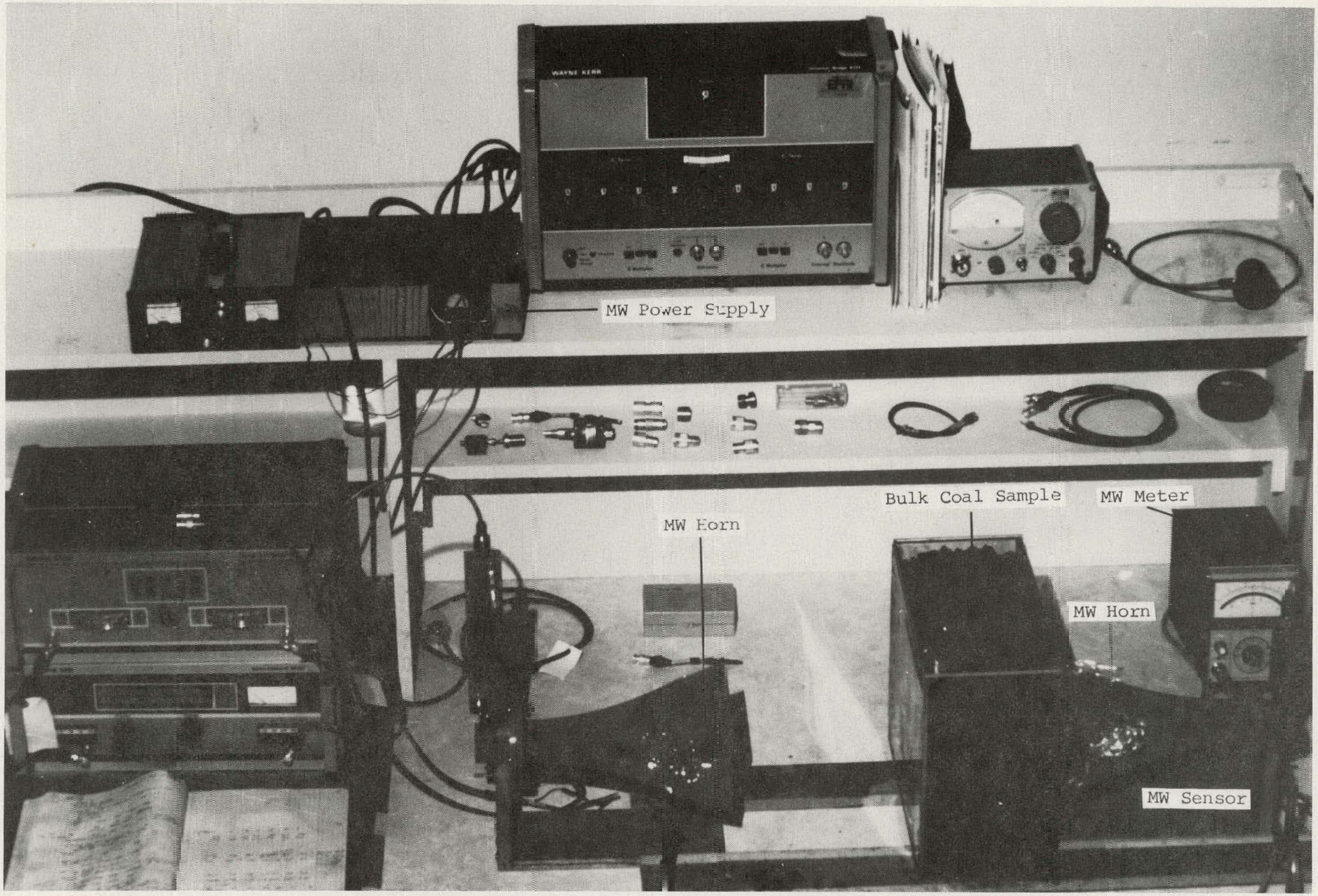


Figure 9. Photograph of Microwave Measurement

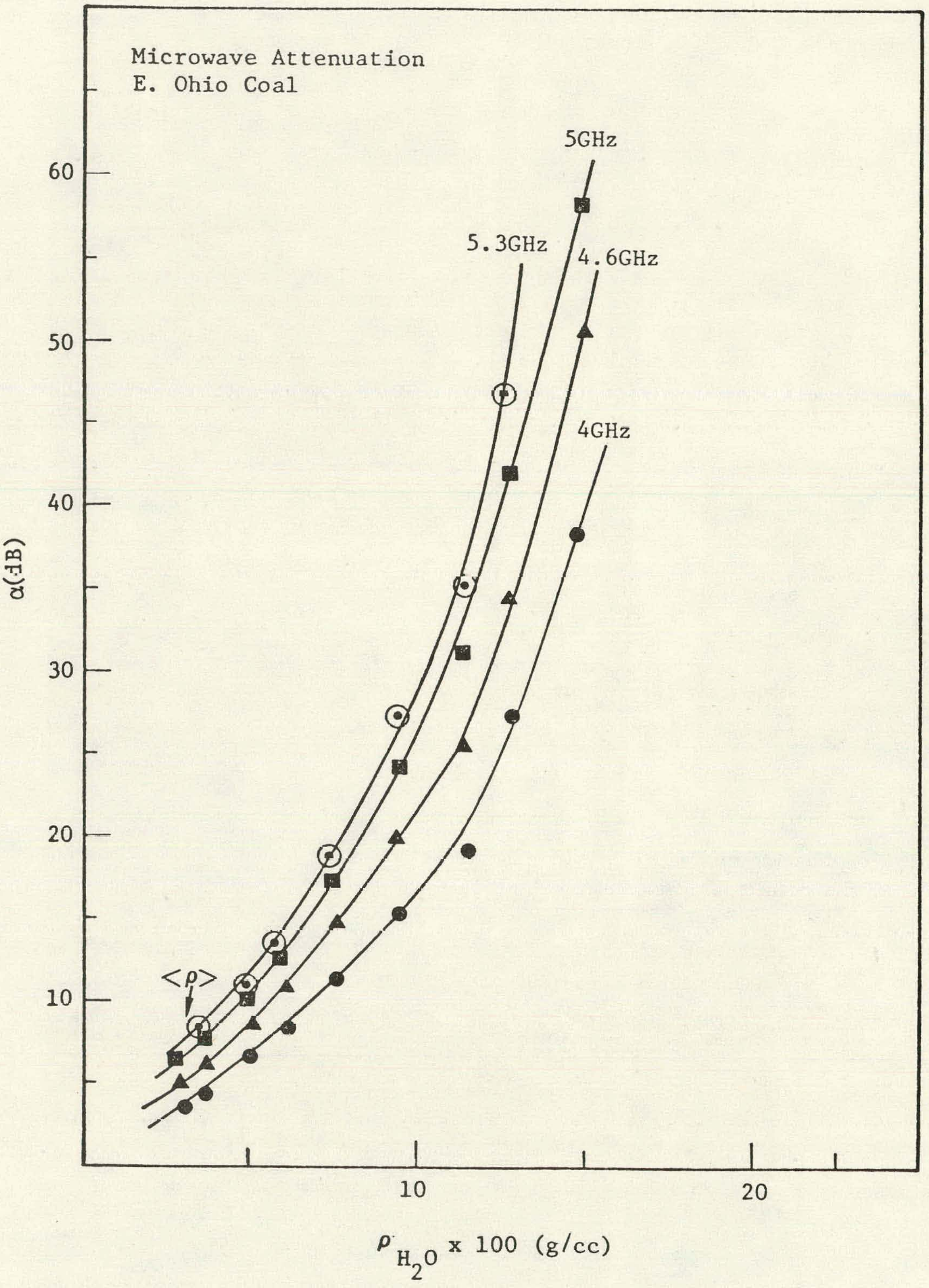


Figure 10. Microwave Attenuation Response for East Ohio Coal Measured at a Range of Frequencies and Moisture Levels

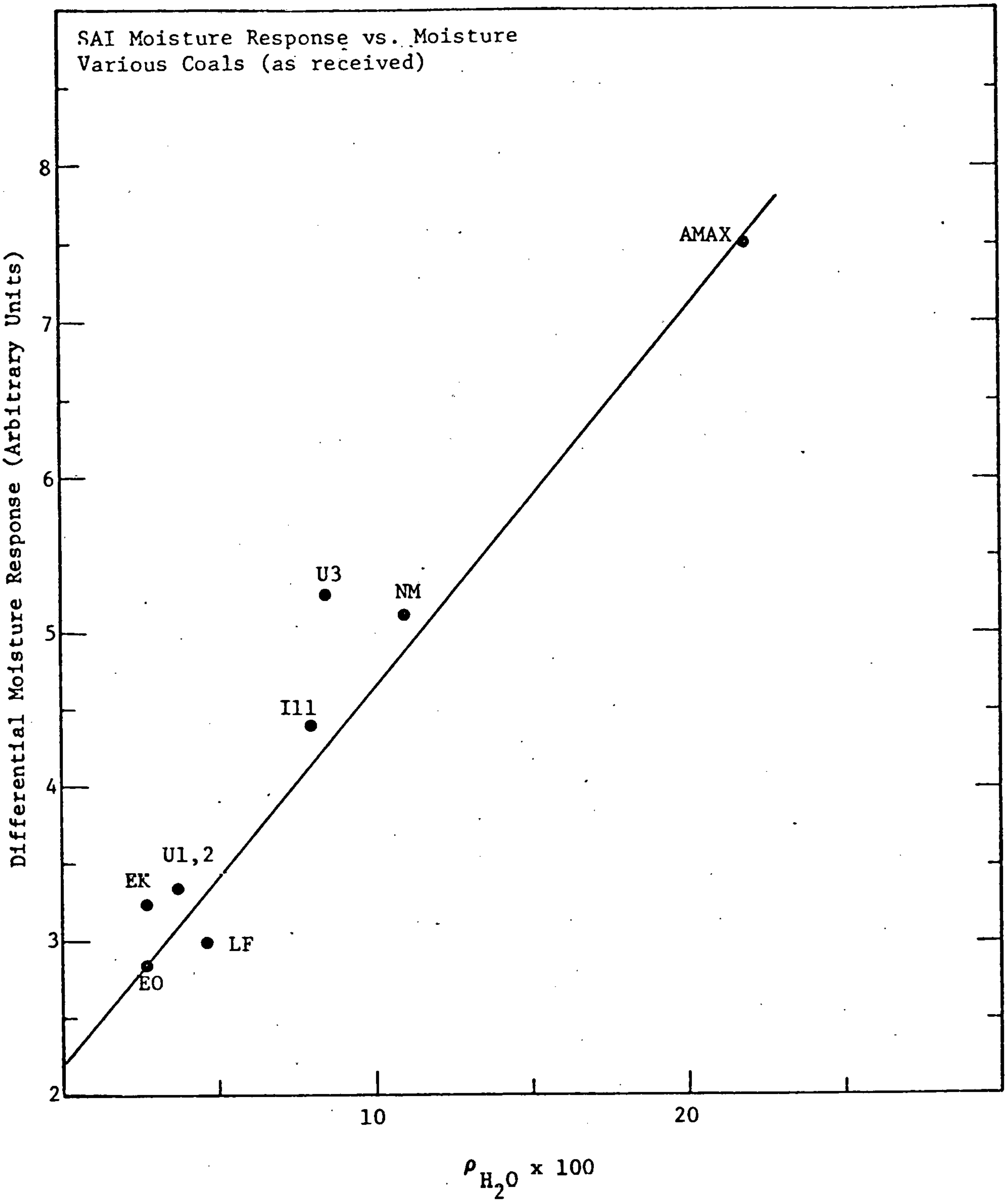


Figure 11. Differential Microwave Attenuation Response for Various U.S. Coal Types

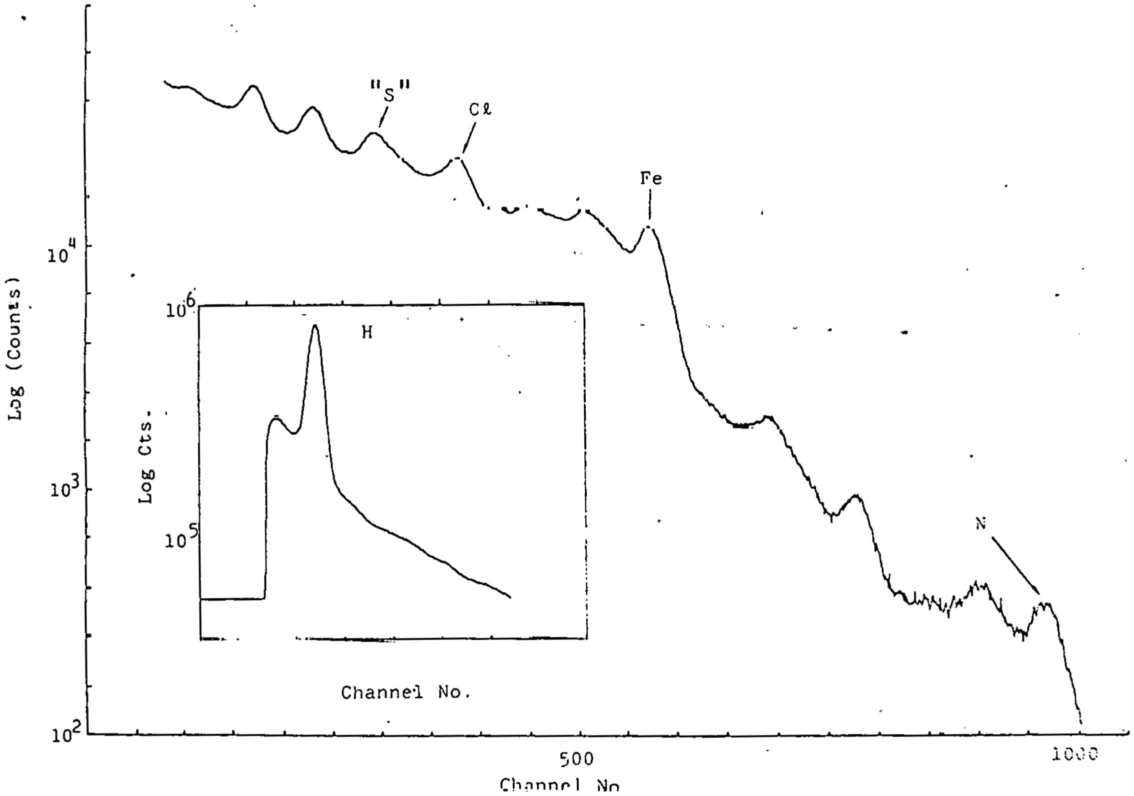


Figure 12. NaI(Tℓ) Spectrum of Pittsburgh #8 Coal

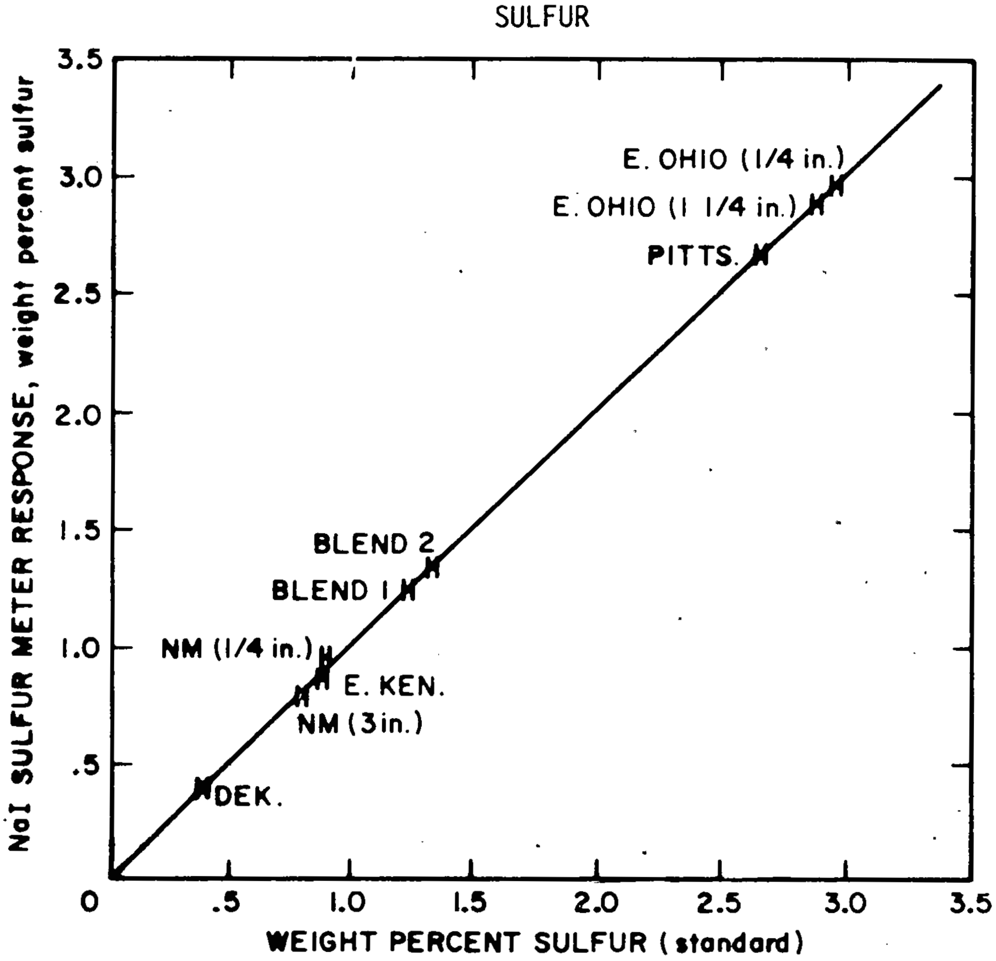


Figure 13. Weight Percent Sulfur Determined from Sulfur Meter Response Plotted Against Standard. Diagonal line represents perfect response.

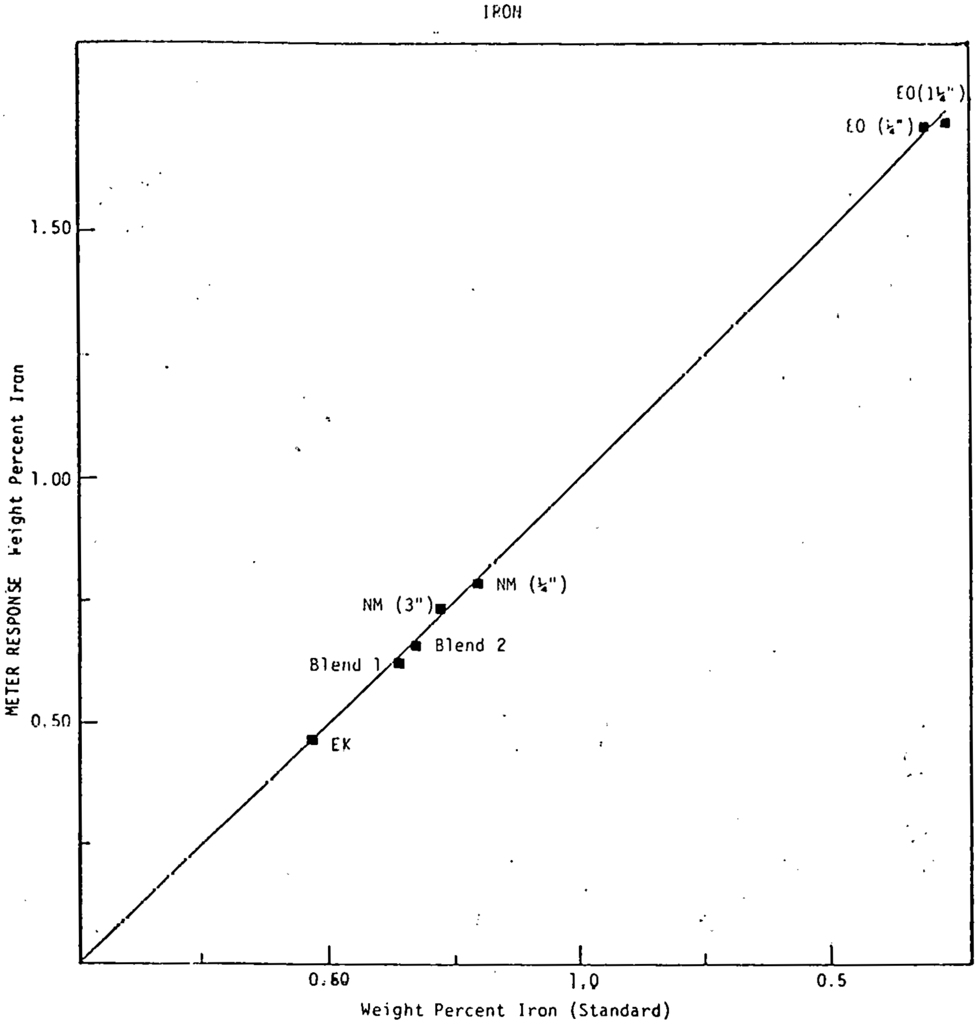


Figure 14. Weight Percent Iron Determined from Sulfur Meter Response Plotted Against Standard. Diagonal line represents perfect response.

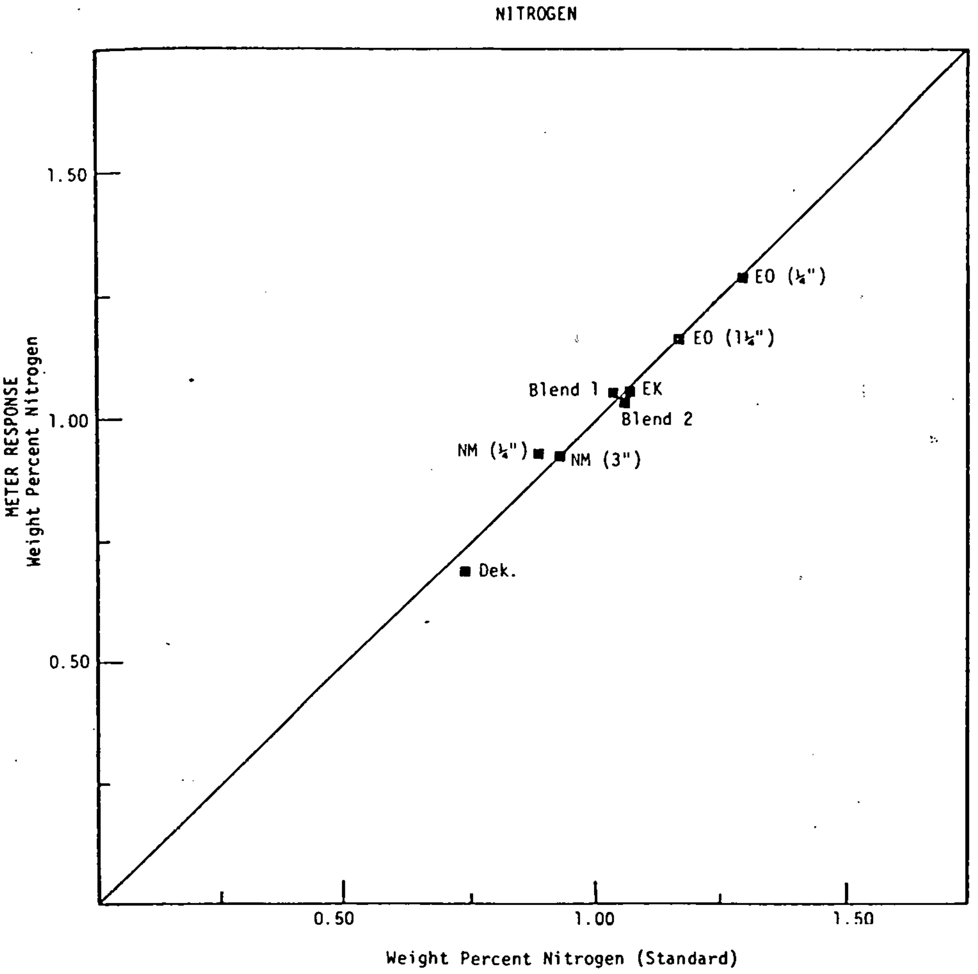


Figure 15. Weight Percent Nitrogen Determined from Sulfur Meter Response Plotted Against Standard. Diagonal line represents perfect response.

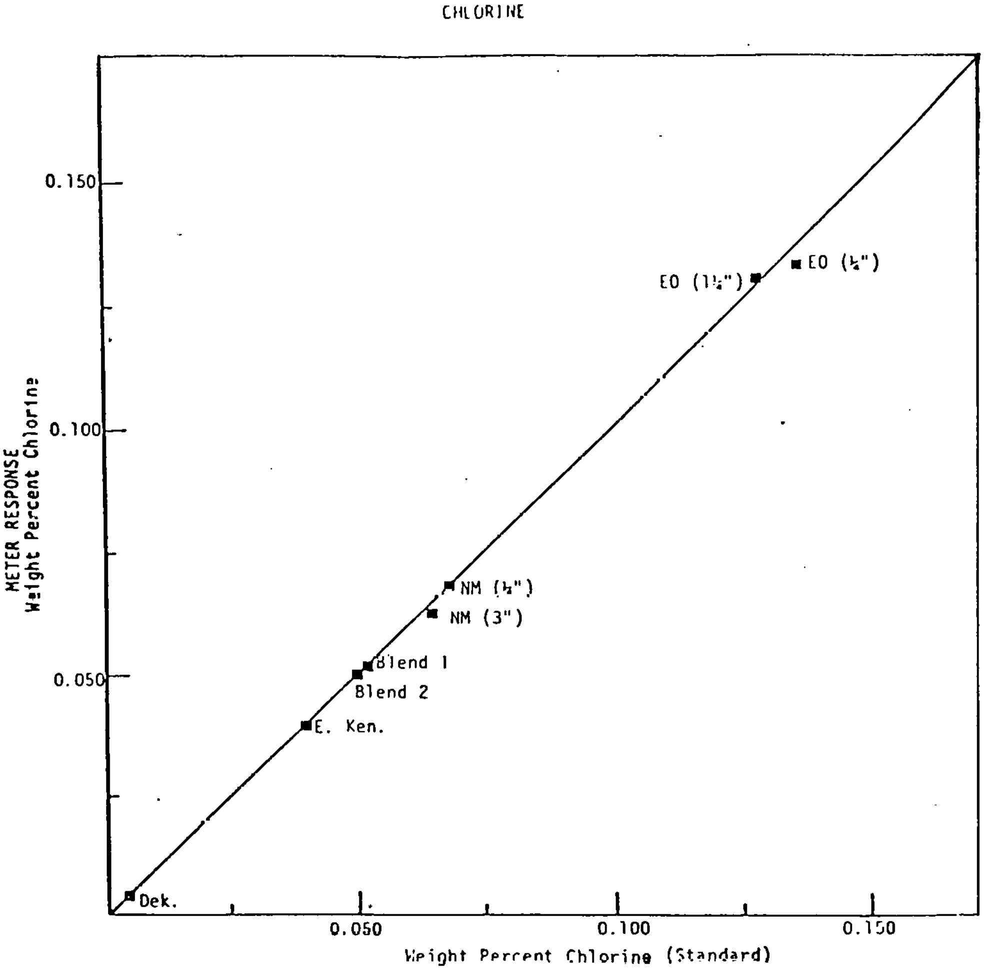


Figure 16. Weight Percent Chlorine Determined from Sulfur Meter Response Plotted Against Standard. Diagonal line represents perfect response.

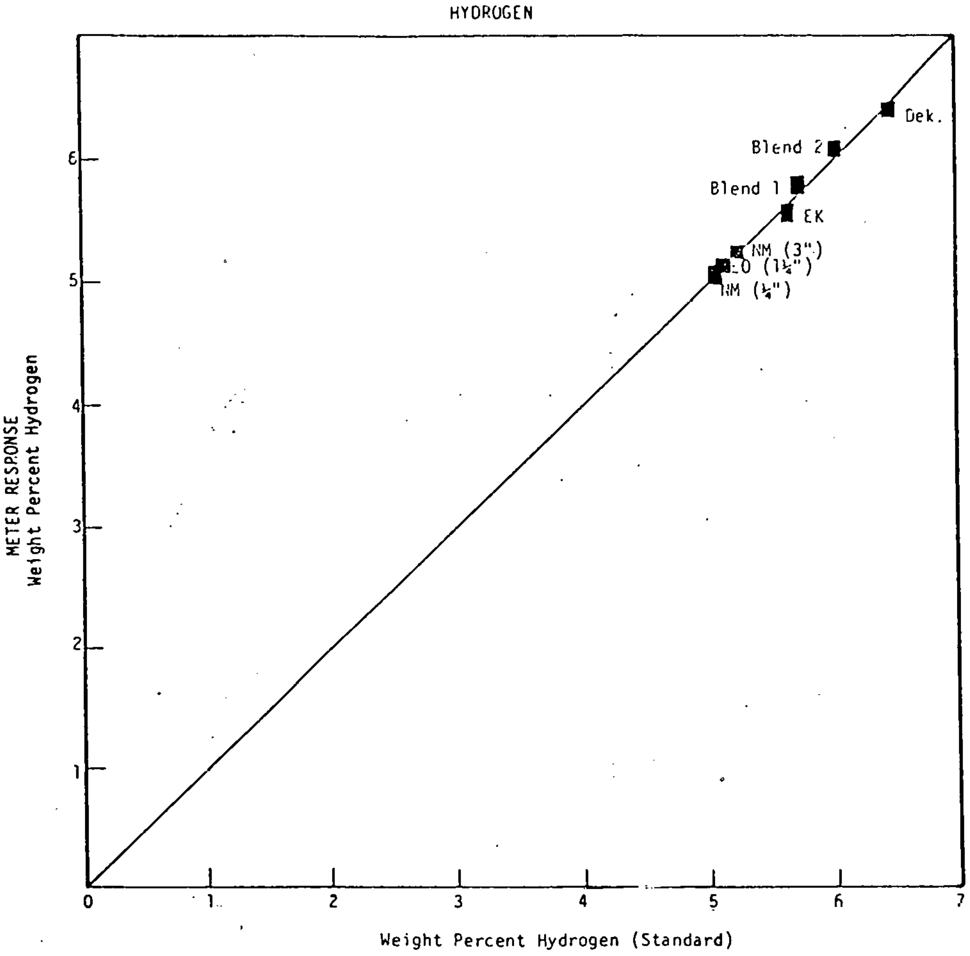


Figure 17. Weight Percent Hydrogen Determined from Sulfur Meter Response Plotted Against Standard. Diagonal line represents perfect response.

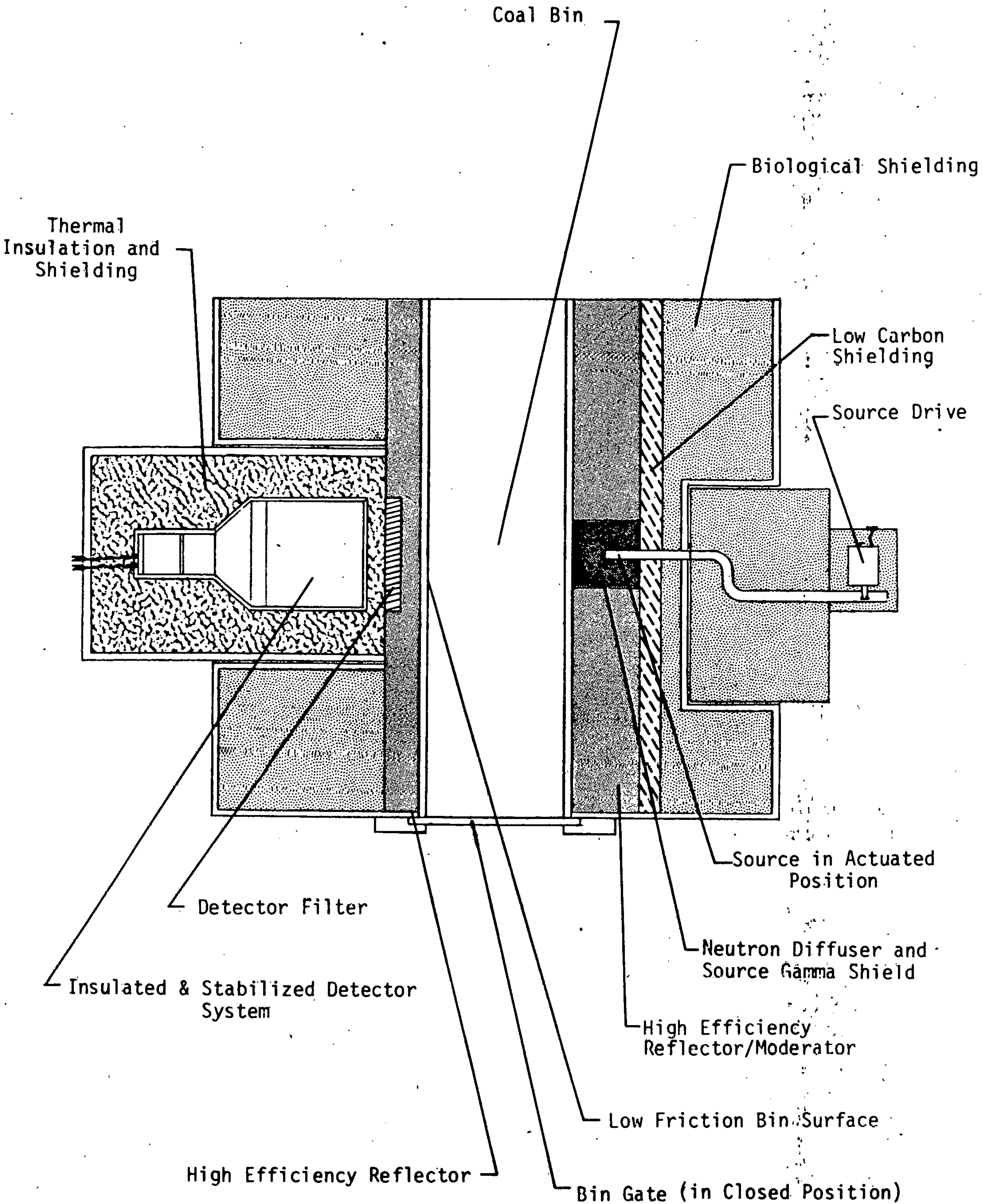


Figure 18. Cross Section of a BIN Type Sulfurmeter

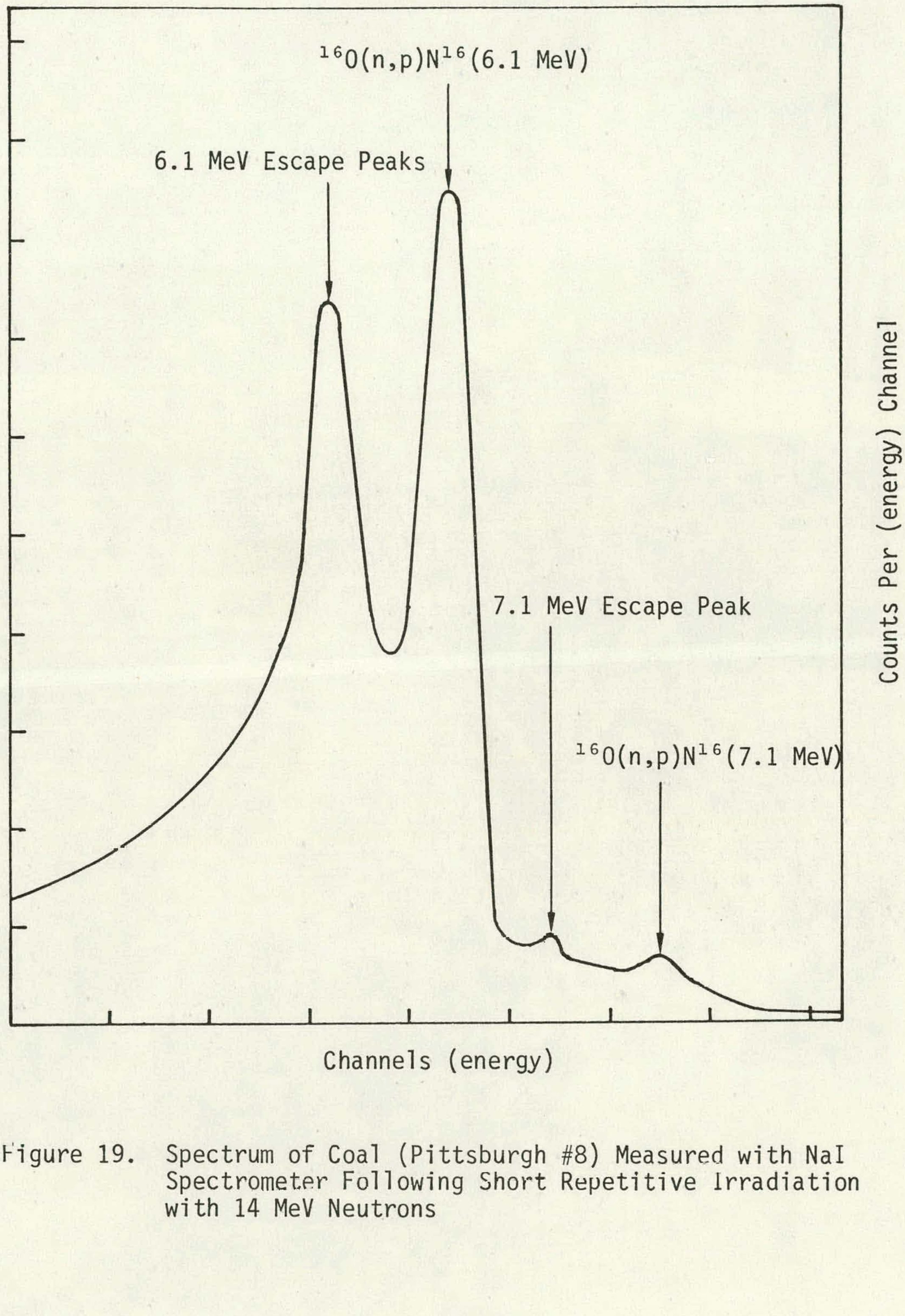


Figure 19. Spectrum of Coal (Pittsburgh #8) Measured with NaI Spectrometer Following Short Repetitive Irradiation with 14 MeV Neutrons

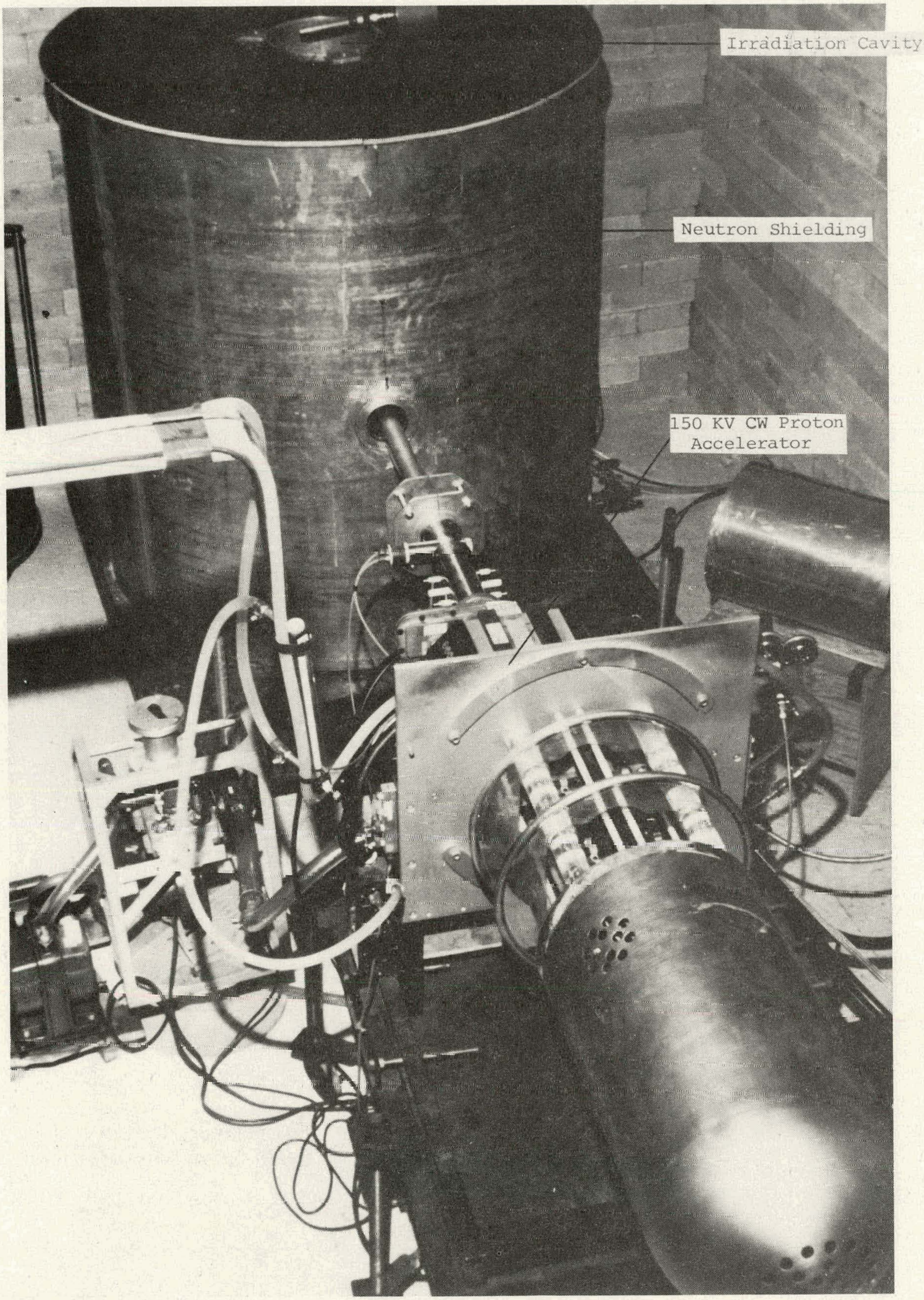


Figure 20. Photograph of 14 MeV Generator

DEVELOPMENT OF AN ELEMENTAL ANALYZER FOR COAL, OIL AND SIMILAR BULK STREAMS - A STATUS REPORT

Presented at

1979 Symposium on Instrumentation and Control
Fossil Energy Processes

August 20, 1979
Denver, Colorado

by

A. Cekorich, H. Deich, T. Harrington

J. H. Marshall III

mdh industries, inc.

DEVELOPMENT OF AN ELEMENTAL ANALYZER FOR COAL, OIL AND SIMILAR BULK STREAMS - A STATUS REPORT

by

A. Cekorich, H. Deich, T. Harrington, and
J. H. Marshall III, MDH Industries, Inc.

The elemental analyzer to be described here has been under development at MDH Industries, Inc., for about five years. This effort has resulted in a new capability for coal-utilizing industries, the ability to analyze a coal process stream on-line, and to obtain information about it in time to utilize that data to affect the coal stream itself and/or its optimum utilization in later processes.

First, who is MDH? We are a small, relatively young company whose capability in developing innovative, high-technology instrumentation rests on the extensive experience of its incorporators with the aerospace instrumentation industry. MDH exists because we felt we could make a meaningful contribution to the country's more normal industrial efforts. We have successfully developed a medical instrumentation line, and are using the return from that line to support the effort to develop our analyzer. This work is totally company funded. There has been no government R & D support behind this work. Based on the results to date, we believe we chose wisely.

The problem we attacked was that of performing elemental analysis of bulk process-stream materials in an on-line configuration. We are interested primarily in the sulfur content of coal (and oil) and secondarily in obtaining data on other elements to permit an ash measurement and, eventually, possibly a BTU measurement.

To perform these measurements, we detect and analyze the gamma rays produced by neutron capture in the material being evaluated. Almost all elements when bombarded by slow neutrons capture these neutrons at least momentarily and form a compound nucleus in an excited state. Usually the rapid emission of one or more gamma rays with energies and intensities which are uniquely characteristic of the capturing nucleus dissipates most of this excitation energy. These gamma rays are called "prompt gamma rays" because they are generally emitted within 10^{-9} s of the time of neutron capture.

The general principles of bulk-composition measurements using neutron capture are available in the literature (including an earlier MDH paper referenced below(1)), and I won't repeat them here, nor cover again why we chose the particular approach we did. I will limit myself here to a description of the actual instrument being built and its capabilities.

---

(1) A. Cekorich, H. Deich, J. H. Marshall III: "An Elemental Analyzer for Coal, Oil and Similar Bulk Streams"; Internal Report No. 3; MDH Industries, Inc.; 25 September 1978. Presented at the ^{252}Cf Utilization Meeting in Atlanta, Georgia, 4 October 1978.

Instrument Description

Figure 1 presents schematic views of the main parts of a coal analyzer employing prompt-gamma analysis. We are currently calibrating this unit and expect to deliver it shortly. The coal being analyzed is confined on four sides within the measurement volume, which is the region throughout which the composition measurement takes place. Coal passing through the coal chute continuously fills the measurement volume with a current coal sample, thus providing the continuous, on-line bulk measurement.

The instrument includes a source of neutrons which is placed outside of the measurement volume. The neutron source consists of two capsules containing the isotope californium-252. (The use of dual sources improves measurement uniformity.) Moderators surround the source capsules in order to reduce neutron energies before the neutrons enter the measurement volume. This energy reduction decreases the number of gamma rays produced by inelastic neutron scattering and resonance absorption and also permits a reduction in the size of the measurement volume.

Californium-252 produces over five gamma rays for each neutron, and gamma rays from neutron capture by hydrogen and carbon in the moderators or in the safety shield could be confused with the same type of gamma rays from the coal being analyzed. The instrument, therefore, includes a gamma-ray shield which is located between the two source capsules with their moderators and the measurement volume. The gamma-ray shield prevents most gamma rays arising from the source capsules, the moderators and the safety shield from reaching the gamma-ray detector or escaping to provide a radiation hazard near the instrument.

The gamma-ray shield also provides a region through which neutrons can readily diffuse from the neutron source into the coal. This diffusion must occur without many neutrons being captured by the materials comprising the gamma-ray shield, because otherwise the gamma-ray shield itself would be an unacceptable source of interfering gamma rays. Thus the gamma-ray shield is composed of materials which have low neutron-capture cross sections as well as high attenuations for gamma rays. Furthermore, its presence along the sides of the measurement volume prevents the surrounding safety shields from depressing the neutron flux at the edges of the measurement volume, thus improving measurement uniformity and instrument sensitivity.

Those neutrons which diffuse through the gamma-ray shield and enter the measurement volume will be moderated by the hydrogen present in the coal, and then many will be captured by the various elements therein. These neutron-capture reactions generally produce gamma rays, which travel outward in all directions. Some of these gamma rays will travel through the measurement volume and the neutron-absorbing gamma-ray window and enter the NaI(Tℓ) gamma-ray detector.

When the gamma rays interact in the detector, they produce electrical signals indicative of their energy. The sensor electronics, which actually consist of two boxes one of which is outside of the radiation shield, convert these electrical signals into digital information, which is transmitted over an interconnecting cable to the display console. The display console processes this information using the fact that neutron capture produces an energy spectrum which depends on the amounts of the various elements capturing the neutrons. The result of this processing is information concerning the relative concentrations of the various elements of interest in the measurement volume and any other properties, such as density, which may be usefully obtained from the measured spectrum.

Although the neutrons which the coal in the measurement volume captures provide the useful information, many neutrons are not captured there and could potentially escape from the instrument or could interact in the gamma-ray detector. Because the neutron sources are outside of the enclosed measurement volume, most neutrons will not enter the measurement volume. In order to control these unused escaping neutrons to avoid a radiation hazard and background in the measured energy spectrum, the instrument includes a gamma-ray window and safety shields.

The safety shield must attenuate source gamma rays, epithermal neutrons, thermal neutrons and capture gamma rays. Because the gamma-ray shield can reduce the dose from source gamma rays by over a factor of 10, neutron attenuation becomes a principal task for the safety shield. Since many of the neutrons leaving the moderators are still energetic, the safety shield must contain a hydrogenous material to reduce the neutron energies to the region where capture is probable. When hydrogen captures thermal neutrons, a penetrating 2.23-MeV gamma ray results, and these capture gamma rays represent a radiation hazard, a potential source of background counts in the detector and a signal which can be confused with that from hydrogen in the coal. Thus, an isotope which does not produce energetic capture gamma rays has been added to the hydrogenous material in the safety shield.

In order to avoid a radiation hazard from escaping neutrons when the measurement volume is empty, the shield on the detector side of the measurement volume has been placed behind the sensor electronics, and the detector and the sensor electronics are thus located within a chamber in the safety shield. Even in this configuration some scattered radiation can leave the top and the bottom of the coal chute passing through the measurement volume when it is empty, because this region is constrained by equipment used to move coal into and out of the instrument. Shielding here should not be necessary, because the scattered radiation is low, and these regions are unoccupied. A radiation alarm and a movable plug for the coal chute when no coal is present reduce radiation hazards for an empty coal chute. In addition, the neutron sources can be withdrawn remotely into a "safe position" to permit entry into the coal chute for short time periods and maintenance of the sensor electronics.

Figure 2 shows a block diagram of data-analysis equipment which is used in this type of instrument. The gamma-ray detector is a doped alkali-halide crystal which scintillates in response to energy deposited by gamma rays entering it. The photomultiplier tube converts these light flashes into current pulses, which the amplifiers increase in magnitude sufficiently to be processed accurately by the analog-to-digital converter. This converter defines forty amplitude windows and categorizes each detected event producing a pulse amplitude within the range of interest as belonging to one and only one such window. In addition, it contains circuits which detect pulse pileup and reject events with pulse amplitudes contaminated by such pileup.

For each such analyzed event, a pulse is added to the appropriate storage register in the accumulators. At the end of a 10-s data-accumulation interval, the relative number of events counted by each of the forty storage registers in the accumulators associated with each of the forty amplitude windows becomes a digital representation of the amplitude of the output pulses from the gamma-ray detector.

As shown in Figure 2, the digital information from the accumulators is presented to the digital data link. The sensor data-link logic converts the data into an appropriate form for transmission over the interconnecting cable to the remotely-located display console. Here the console data-link logic receives the transmitted data and presents them in proper form for the computer.

The console contains a microprocessor with sufficient memory and peripheral equipment to form a small digital computer. After making corrections for pulse pileup, this computer constructs weighted linear sums of the count rates in each of the forty amplitude windows to increase selectively the sensitivity to one element while decreasing the sensitivity to other interfering elements. Several such sums with different weighting coefficients yield outputs which are indicative of the relative concentrations of different elements. The computer generates elemental sums corresponding to carbon, hydrogen, sulfur, nitrogen, silicon, iron, aluminum, titanium, calcium, potassium, sodium and chlorine in order to encompass most of the elements present in coal. The optimization process leading to the weighting factors considers pulse pileup, gamma rays from the ^{252}Cf neutron sources, signals induced by neutron reactions in the detector, gamma rays from structural materials, and drifts in the pulse height analysis. This type of computation eliminates most of the interferences between elements capturing significant fractions of thermal neutrons and also corrects automatically for the slowly-varying continuum. Normalization to one element or group of elements removes the problems inherent in using absolute counting rates.

The resulting quotients, which for a coal-analysis instrument will represent the fraction by weight of each of the measured elements compared principally to carbon, are presented to the data-outputting sub-system for further uses. The data-outputting sub-system can contain strip-chart recorders for generating graphs of relative elemental concentrations versus time, digital displays for showing these concentrations in numerical form, and a data interface for providing digital communication to external data-processing devices such as digital printers or plant-controlling computers.

Because drifts in the electronics for gamma-ray analysis are a significant source of error, the instrument contains a stabilizing system. This system has a temperature regulator, which maintains the sensor electronics and the gamma-ray detector at a constant temperature for ambient temperatures between -30°C and +45°C. The stabilizing system can also vary the gain of the pulse-height-analysis circuits using a digital-to-analog converter and a controllable power supply to change the bias voltage applied to the photomultiplier tube. A second digital-to-analog converter permits the stabilizing system to change the offset of the pulse-height-analysis circuits by way of the amplifiers, resulting in a two-point control of the pulse-height analysis. The computer then can cause two peaks in the gamma-ray spectrum to be centered in appropriate amplitude windows, reducing the effects of drifts in the electronics for gamma-ray analysis.

Accuracy and Response Time

During the production of this instrument for the measurement of the sulfur and ash contents of a cleaned, low-ash coal, MDH developed a computer model of the operation of this type of elemental analyzer. This model is based on both theory and experimental data and simulates in detail much of the operation of the meter. This simulation permits us to predict measurement accuracies for a given response time and coal composition within at least a factor of two. This factor of two allows conservatively for uncertainties in the computer model itself and for presently-unknown sources of error. Further work on present projects will permit this factor to be reduced as the computer model continues to be refined.

Table 1 shows the predicted errors and readouts for a particular coal, the "cleaned" coal for which the current unit was built. For example, the fraction of the dry coal by weight which is sulfur is nominally 0.92%. The instrument will read out this value with an anticipated error of 2.2% of the value or, to state it another way, it will read out the % sulfur as 0.92% ±0.02%. This readout will be up-dated every 10 seconds based on the output of an exponential filter operating on all past data with a response time as shown. Such a filter weights the latest data heaviest, with continuously decreasing weights on older data.

The total errors listed are comprised of a combination of two types of error, those we call systematic errors and those we call statistical errors. The statistical errors are improved by extending the response time of the filter (essentially smoothing over more data). We have chosen the response time to be such that the statistical errors and the systematic errors, those errors independent of response time, are approximately equal. The systematic errors represent an irreducible minimum error which only instruments with very long response times can achieve.

The ash percent readout listed below the table shows a total error of ±0.124%. The analyzer does not actually measure "ash". It can only establish the elemental composition of the material being evaluated, and does not recognize chemical states. Therefore, the "ash" readout is obtained by assigning previously agreed upon forms to the various ash elements, such as Fe_2O_3, SiO_2, Na_2O. The fractions by weight for the elements are increased by appropriate factors to allow for the associated, but unmeasured, oxygen. Other minor elements are not measured, usually because there is too little of each, and, for this cleaned coal, a correction factor of 1.02 is used to account for these unmeasured elements. The resultant output, an anticipated 2.73% for this coal, will be measured with an error of ±0.124% as previously noted.

The moisture measurement will be obtained by mostly external means. A microwave absorption measurement, with the assistance of density corrections obtained from the analyzer, is expected to provide an accurate value for this parameter.

Using all the above data in a previously agreed upon formula from Mott and Spooner, the heat content of the coal stream is estimated. Finally, the estimated heat content is divided into twice the measured amount of sulfur to provide a measurement of the amount of SO_2 per unit heat output. This output does not allow for any of the sulfur remaining in the discarded "ash", but it should track the stack monitors well.

The LCT coefficients used to produce this data assume that the material being analyzed will vary over known bounds. All the elements (except carbon, of course) are assumed to vary by ±100% in an uncorrelated manner. That is, while any element is varying randomly, it is not expected that all ash elements would go the same way causing the ash content to double.

To show how the instrument would perform for an uncleaned coal, we prepared Table 2. Note the lower carbon, and the significantly higher sulfur, ash and moisture. Because there is much more to work with, the errors as a percentage of the quantity being measured (other than carbon) are generally improved; but, for the same reason, the errors as a percentage of the coal are increased. Thus, the sulfur would be read out as 3.57 ±0.066%, the ash as 11.2 ±0.25%, and the lbs. $SO_2/10^6$ BTU as 5.58 ±0.096. These accuracies are achieved using different LCT coefficients, again allowing ±100% variation around the new norm. Changing LCT coefficients, and thereby optimizing the analysis for widely different coals, would call for a change of one board in the data processing electronics.

Equipment Status

I would like to close this presentation by showing some photographs of the actual equipment to be delivered soon. Figure 3 shows the Sensor Assembly from two aspects. The man at the edge of the picture is for scale reference. He is six feet tall. Because this picture was taken during radiation safety checks, we omitted the thermally insulated connection between the Sensor Assembly and the Logic and Power Assembly, which you would normally see coming out of the white face in the left view. The Sensor Assembly is about eight feet high and weighs about eight tons. Figure 4, with one of the shield tanks removed, gives a clearer presentation of coal chute, source and moderator relationships. The void to the rear in this figure is the cavity containing the detector and initial signal processing electronics as well as thermal insulation and some additional radiation shielding materials.

Figure 5 shows the Logic and Power Assembly. The distance between this unit and the sensor (along the thermally insulated connection) is fixed at six and one half feet to handle some very high speed signals between the two units, where transmission time can affect performance. This figure shows the only item requiring maintenance by operational personnel in the analyzer. The analyzer will announce when the air filters for the thermal control system have accumulated so much dust and dirt that they must be cleaned to maintain proper control system performance. The filters are standard automobile-type units, so that maintenance should be straightforward. The scale resting on the top of the unit is a one-foot rule to give the viewer a concept of overall size.

Both of these units, the Sensor Assembly and the Logic and Power Assembly, are designed to meet National Electrical Code Class 2, Division 1, Group F conditions. They do not need special facilities for proper operation. The thermal control system is expected to perform properly over an ambient temperature range from -30°C to +45°C.

The control room equipment (Figure 6) is almost completely contained in a standard 19" rack. If space is at a premium, we need only 29 1/2 inches of vertical rack space to hold all these units. The four items shown here are the power supply, the computer-processor, the control panel and a chart recorder. Digital readouts occupy the majority of the face of the control panel, providing large digits readable from a distance. The cluster of indicators and switches on the right contain the following (reading left to right, row by row):

- Control Fail: Tells the operator when it is not lit that the computer is running thru its paces in a normal mode and re-triggering an inhibit circuit every ten seconds. Since the complete control and data processing cycle is performed in a 10-second interval, if the computer should ever get hung up somewhere, this indicator would go on. Another possibility for the indicator to come on would be power loss to the computer.

- Data Valid: This is the normally lit green light saying everything is okay so far as any of the circuitry can determine.

• Sensor Off:	Indicates there is no power at the sensor installation, even though everything seems alright in the control room.
• Check Filter:	The previously described flag for air filter maintenance.
• Micro Water/ Elan Water:	A selection by the operator telling the computer to use the microwave moisture measurement input or the elemental analyzer a priori input of 6% moisture.
• Power Fail:	A normally energized circuit which trips on any short power failure. Even if power returns quickly and the system continues to perform, the operator must reset this switch to tell the computer that the intermittent failure was duly noted.
• Chart Zero:	A signal to set the range of the pen recorder at zero.
• Chart Full Scale:	A similar signal to set full scale.
• Lamp Test:	A switch to allow the operator to test the lamps by holding down the switch. Upon release, the computer cycles its logic and relights the lamps for 10 seconds to indicate that the circuits are also functioning properly.

The last switch is protected by an access cover. "Restart" causes the system to re-initialize and run thru its entire start-up sequence. We therefore want the operator to use this switch only when he really intends for this sequence to be followed.

The chart recorder provides running graphs of the outputs shown on the digital display. Other detailed data which can be recorded and used at a later date is put on the printer (Figure 7). Any of the numbers which occur in the analytical cycle could be called up and recorded, if desired, on command. Current plans call for the operator to call for a print-out once per shift, at which time 24 hours worth of history will be printed. With this much redundancy, all the data could be recorded despite operator omissions.

Element	Dry Coal Fraction By Weight Ki (%)	LCT 1/e Response Time (min)	Total Error In Dry Coal Weight Fraction	
			% of Coal	% of Ki
Carbon	85.9	8	0.21	0.24
Hydrogen	5.36	8	0.09	1.6
Nitrogen	1.57	8	0.024	1.5
Sulfur	0.92	8	0.02	2.2
Chlorine	0.16	8	0.0023	1.5
Calcium	0.133	64	0.037	27.9
Iron	0.357	64	0.0056	1.6
Silicon	0.526	64	0.0044	8.4
Aluminum	0.427	64	0.034	7.9
Titanium	0.034	64	0.002	5.7
Sodium	0.061	64	0.016	26.1
Potassium	0.055	64	0.021	38.1
Nickel	0.003	64	0.00025	8.2
Chromium	0.007	64	0.0023	9.5

Ash - %: 2.73 ±0.124
Moisture (Fraction By Weight) - %: 6.0
Theoretical Heat Content - MJ/Kg: 33.24 ±0.087
Lbs. $SO_2/10^6$ BTU: 1.2 ±0.025

TABLE 1

"CLEANED" COAL

Predicted Errors and Readouts

All errors are expressed as one standard deviation of value. An expressed error includes the theoretical contribution of statistical, systematic and discriminator drift effects, but does not include the effects of density variation correction or moisture measurement error or any inherent inaccuracies of the formulas.

Element	Dry Coal Fraction By Weight $\overline{K}i$ (%)	LCT 1/e Response Time (min)	Total Error In Dry Coal Weight Fraction % of Coal	Total Error In Dry Coal Weight Fraction % of $\overline{K}i$
Carbon	69.7	8	0.38	0.55
Hydrogen	4.82	8	0.11	2.2
Nitrogen	1.41	8	0.028	2.0
Sulfur	3.57	8	0.066	1.8
Chlorine	0.0333	8	0.00085	2.6
Calcium	0.316	64	0.037	11.8
Iron	1.60	64	0.028	1.8
Silicon	2.61	64	0.070	2.7
Aluminum	1.25	64	0.055	4.4
Titanium	0.0625	64	0.0030	4.8
Sodium	0.0412	64	0.017	40.3
Potassium	0.221	64	0.035	16.0

Ash - %:	11.2 ±0.25
Moisture (Fraction By Weight) - %	9.99
Theoretical Heat Content - MJ/Kg:	26.68 ±0.068
Lbs. $SO_2/10^6$ BTU:	5.58 ±0.096

TABLE 2

"MEDIUM-HIGH S" COAL

Predicted Errors and Readouts

All errors are expressed as one standard deviation of value. An expressed error includes the theoretical contribution of statistical, systematic and discriminator drift effects, but does not include the effects of density variation correction or moisture measurement error or any inherent inaccuracies of the formulas.

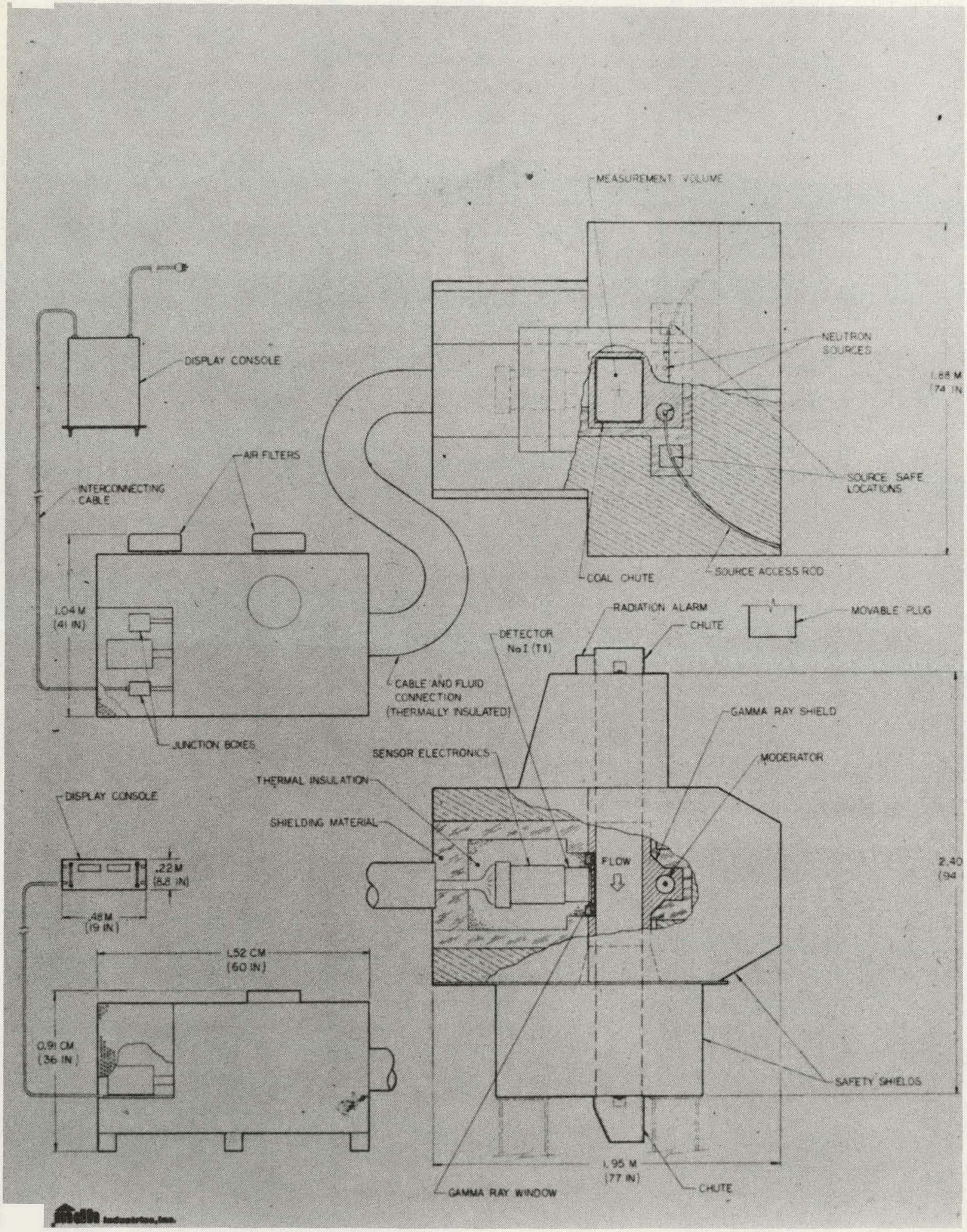


FIGURE 1

COAL ANALYZER SCHEMATIC VIEWS

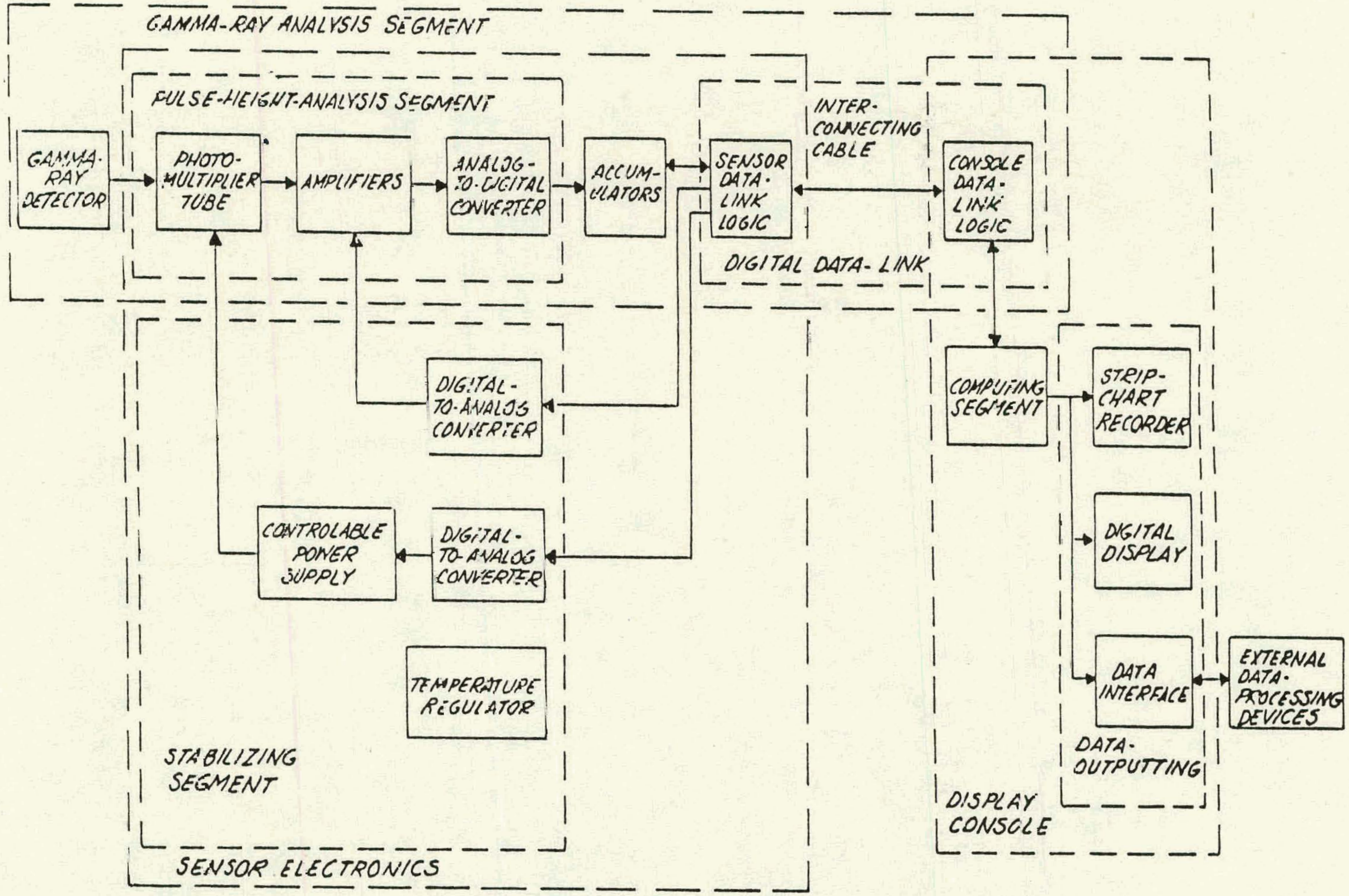


FIGURE 2

DATA-ANALYSIS EQUIPMENT

Block Diagram

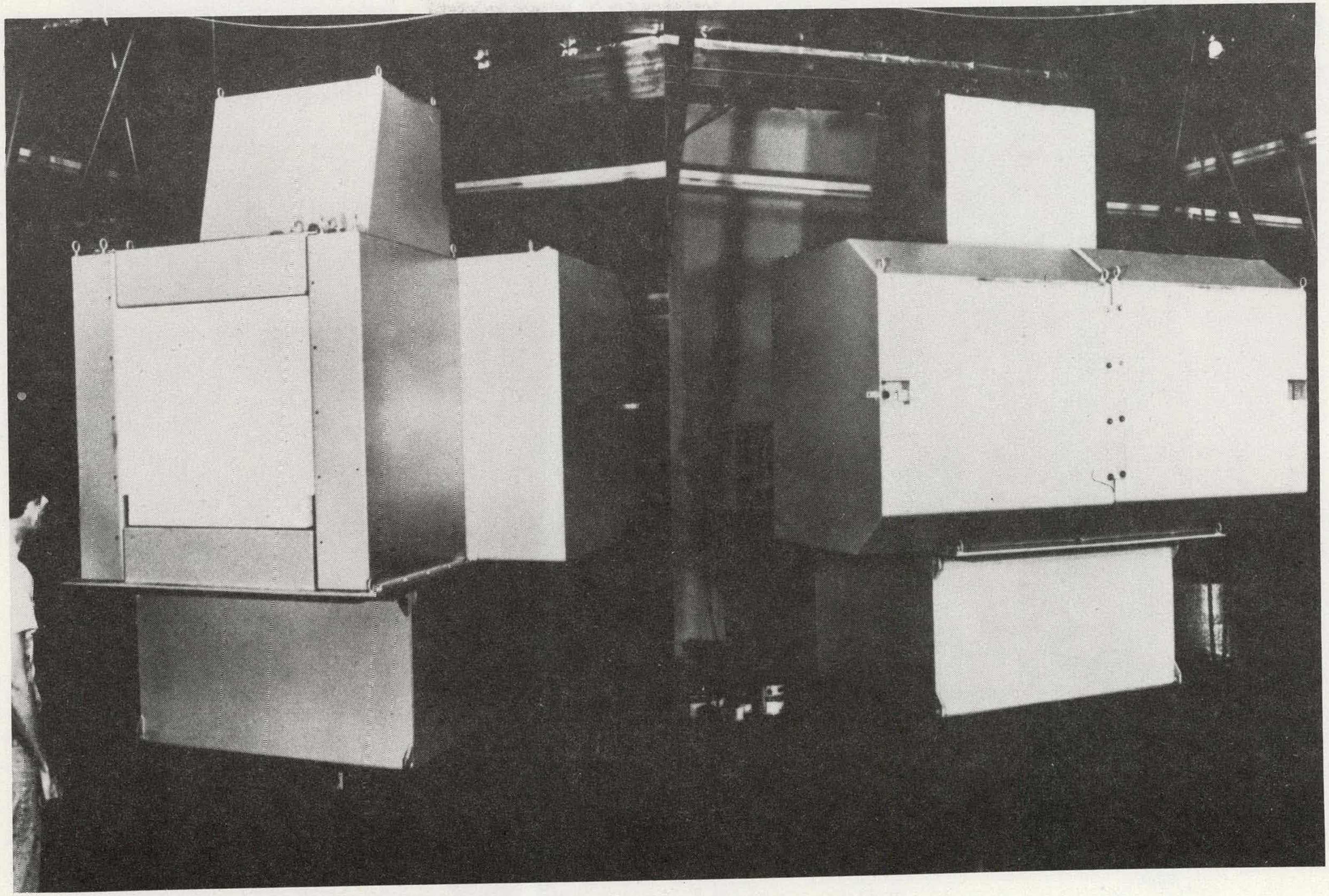


FIGURE 3

MDH MODEL 1049 ELEMENTAL ANALYZER

TWO VIEWS OF SENSOR ASSEMBLY

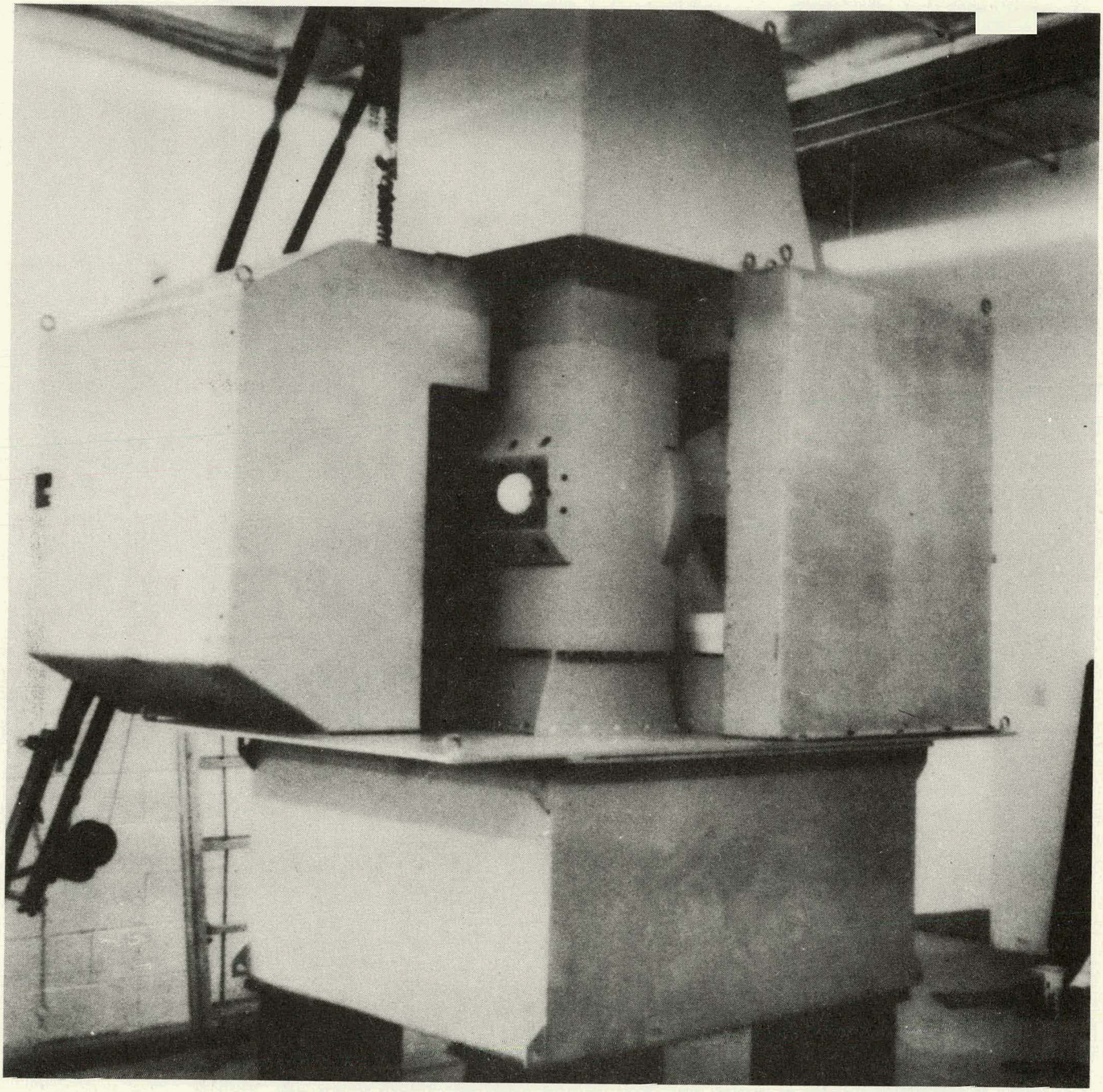


FIGURE 4

"SENSOR CUTAWAY"

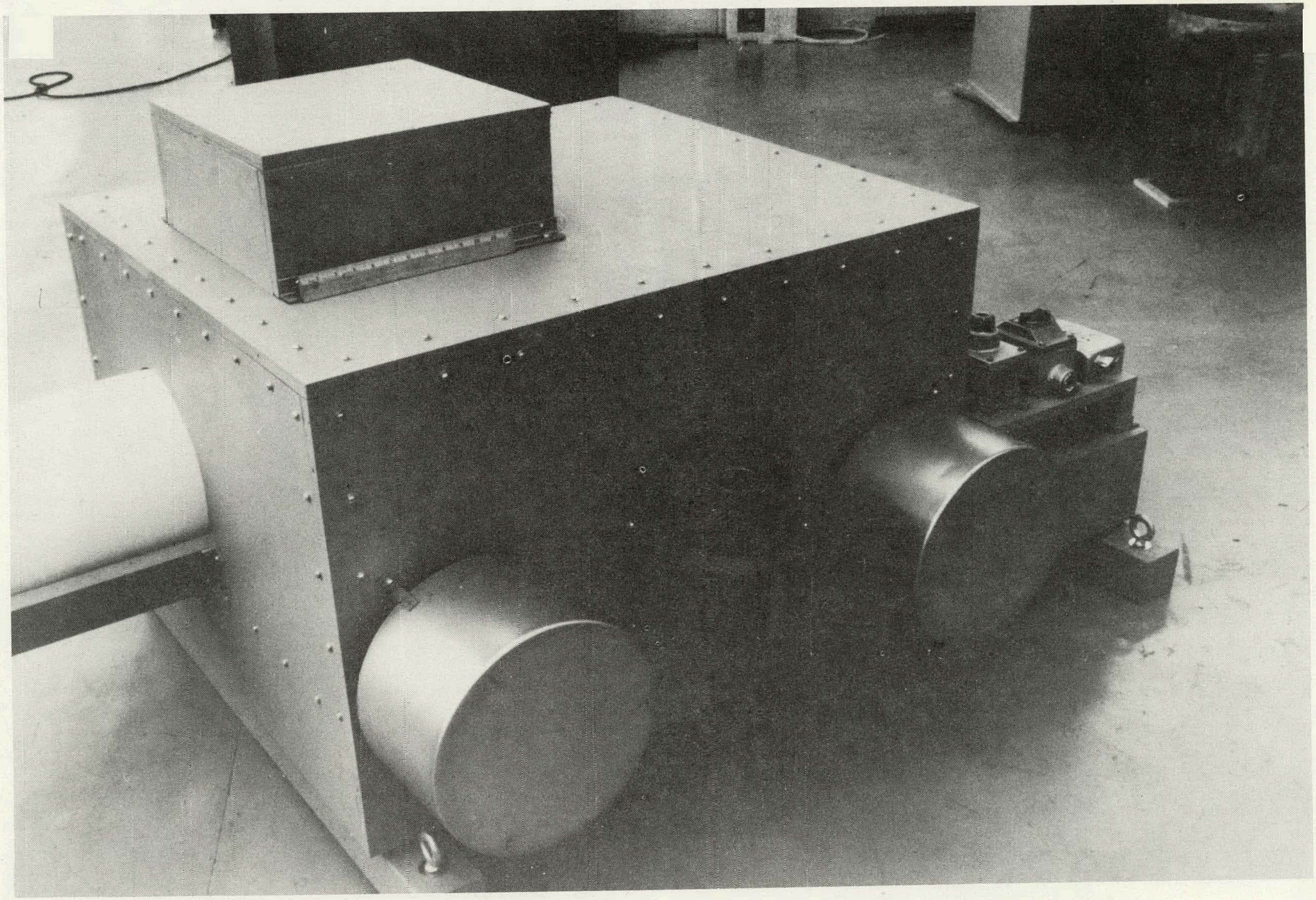


FIGURE 5

"LOGIC AND POWER ASSEMBLY"

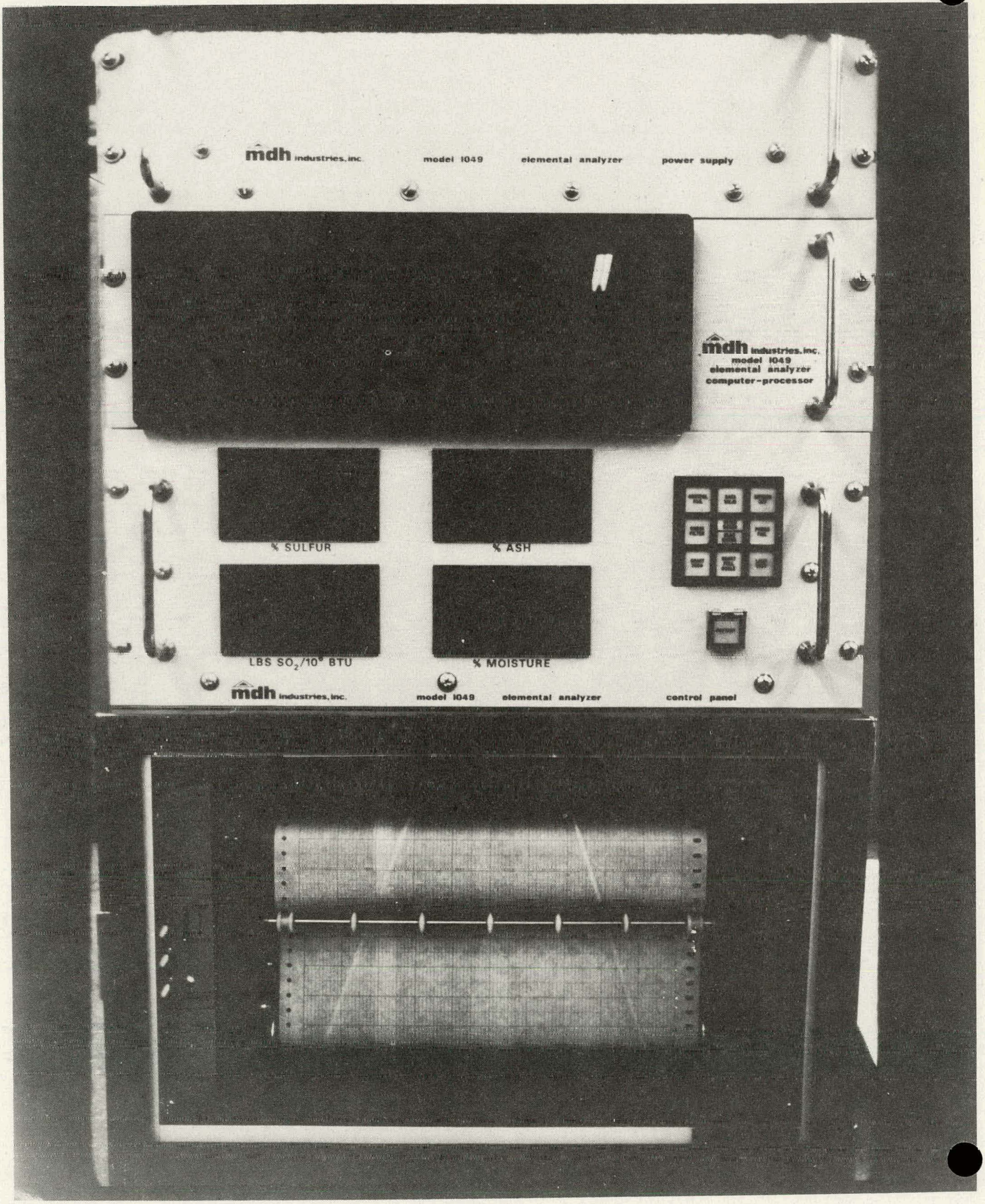


FIGURE 6

CONTROL ROOM EQUIPMENT

FIGURE 7

PRINTER

DESIGN AND INITIAL TESTING OF HIGH TEMPERATURE/PRESSURE SAMPLERS

T. R. Bump and H. Chang
Components Technology Division
Argonne National Laboratory
Argonne, Illinois 60439

ABSTRACT

The ANL High Temperature/Pressure Samplers Program develops, under guidance of the Morgantown Energy Technology Center (METC), samplers for installation at selected locations in coal-process PDU, pilot, and, eventually, Demonstration plants, to improve monitoring of plant performance. Two samplers have already been designed and procured, a Non-insertable, Isothermal Gas Sampler and an Insertable Pyrometer. The former component is designed to collect gas samples near the wall of a water-cooled coal process vessel, such as the METC low-Btu gasifier, and deliver the gas isothermally to an analyzer. The sampler line heaters and their control console, which controls the heaters at the gas sample stream inlet temperature, have already been tested at 1500°F. Also, the pressure letdown system, which provides for a 300 psi drop from gasifier to analyzer, has been calibrated for use as a flowmeter.

The Insertable Pyrometer is designed to penetrate into the interior of a pressurized coal-process vessel, such as the METC gasifier, and measure radial temperature distributions, to at least 2000°F. The reference probe houses a quartz rod that transmits infrared signals from the vessel interior to a signal analyzer outside the vessel. The entire component has already operated satisfactorily away-from-vessel. In addition, an Insertable, Combined, High-velocity Thermocouple and Isothermal Gas Sampler, that combines many features of the first two components, has been designed and is under procurement. Finally, the conceptual design of a Coring-type Solids Sampler has been completed.

INTRODUCTION

Current coal-process PDU and pilot plants operate essentially as "black boxes," with characteristics of the process ingredients known only at the inlets and outlets of the process streams. Basic engineering data are needed for other locations within plant process streams operating at high temperatures and pressures; therefore, it is essential to install samplers to determine the extent of reaction completion and other process parameters, at those locations. A recent example of such a sampler for a non-coal process application is described in Ref. (1). Reference (2) describes samplers for coal-process use, but these samplers are intended primarily for characterization of particulates in gasifier product streams.

Because samplers for coal-process use are generally unavailable, ANL has been funded by DOE to develop them, under the guidance of the Morgantown (WV) Energy Technology Center (METC). Two samplers have already been designed, fabricated, and partially tested: a Non-insertable, Isothermal Gas Sampler, and an Insertable Pyrometer. A third unit called an Insertable, Combined, High-velocity Thermocouple and Isothermal Gas Sampler, has been designed and is currently under fabrication. A fourth unit, a Coring-type Solids Sampler, has been brought through the conceptual design stage. Details of each of these samplers are given in the following sections.

NON-INSERTABLE, ISOTHERMAL GAS SAMPLER

This component, with nominal design conditions of 300 psig and 1500°F, is designed to collect an up-to-100-std-ℓ/m gas sample stream near the wall of a water-cooled coal-process vessel, such as the METC low-Btu gasifier, Ref. (3), and deliver the gas isothermally to a spectrometer for on-line analysis. Isothermal delivery is required to maintain the sample stream in chemical equilibrium so that ex-vessel spectrometer data can be readily extrapolated to indicate gas compositions inside the vessel. A side benefit of isothermal delivery is that tar condensation in the sample stream is discouraged, thereby increasing analysis accuracy and decreasing the possibility of sample line plugging. Gasifier gas compositions are of interest to METC researchers because, in their efforts to develop improved product stream cleanup systems, they desire to correlate gasifier operating conditions with performance of cleanup system components.

Because heat loss conditions vary considerably along the sample line between vessel and analyzer, seven separate heaters are provided. Each of the heaters is controlled independently to maintain the local sample line temperature equal to that of the gas entering the sample line. The gas inlet temperature is measured by a "high velocity thermocouple," Ref. 4. Such a thermocouple is designed to (a) promote convective heat transfer to the thermocouple hot junction by providing high gas velocity at the junction, and (b) reduce radiative heat transfer from the hot junction, by surrounding the junction with a radiation shield(s), preferably heated to the junction temperature. In this way, the junction temperature can be very close to that of the gas passing the junction.

Three of the seven heaters are incorporated in an Alumina Heater, Fig. 1, which is comprised of three lengths of doubled, 20 ga., Incoloy 800 wire* wound at three axial locations on a 3/8 in. OD x 1/4 in. ID x 38 in. long high-purity alumina tube. The wire is bonded to the tube, and electrically insulated, with alumina cement, and covered with Refractory Products WRP-X-AQ thermal insulation. Also bonded to the tube are control and limit thermocouples, one each for each heater, consisting of 1/16 in. OD, Inconel 601 sheathed, ungrounded, Type K wire. The gas inlet temperature is measured with a similar thermocouple (the high velocity thermocouple) that travels the length of the alumina tube between the heater wire and thermal insulation and is bent to enter the inlet end of the tube as can be seen in Fig. 1. In event of failure of this thermocouple, a backup unit, centered by "spiders," would be installed along the axial centerline of the tube.

---

*Incoloy 800 (and Inconel 601) are used because of their superior resistance to sulfidation. Alumina is used because of its chemical inertness and high-temperature strength.

The Alumina Heater serves to carry the gas sample stream isothermally through the gasifier water jacket. The Heater thermal insulation fits snugly inside a 1-1/4 in., Sch. 40 Incoloy 800 horizontal pipe that is attached to the inner wall of the water jacket and provides a gas-water pressure boundary. That Incoloy pipe in turn is centered inside an existing 2 in. carbon steel nozzle, Fig. 2, welded to the water-jacket outer wall. The nozzle is flanged to a bellows Expansion Joint welded at its other end to the outboard end of the 1-1/4 in. Incoloy pipe. The Expansion Joint allows for differential expansion between Incoloy pipe and 2 in. nozzle, and is provided with a tap to allow cooling water to circulate from the water jacket, through the nozzle and Expansion Joint, and on to the suction of the water jacket circulating pump.

The outboard end of the Expansion Joint is flanged to a Type 316 stainless steel Spool Piece of 6 in., Sch. 40 pipe, Fig. 3, that is flanged in turn to a Tapered Connection, Figs. 4 and 5. The Tapered Connection provides a loose connection between the Alumina Heater and downstream metal sample lines. The Tapered Connection is centered about a 3/4 in., Sch. 80 Incoloy 800 pipe that has a loose socket for the Alumina Heater's alumina tube at one end and an Autoclave 9/16 in. OD tubing, Type 316 stainless steel modified coupling at the other. The Incoloy pipe is wound with a controlled heater to allow carrying the sample gas stream isothermally from the Alumina Heater to a Throttle and Shutoff subassembly, composed primarily of Autoclave fittings, that leads to the sample analyzer. Two reducers connect the 3/4 in. pipe to a 6 in. flange that is bolted to the outboard end of the Spool Piece. The two reducers provide a gradual temperature transition from the up-to-1500°F 3/4 in. pipe to the cool Spool Piece. Conservative calculations indicate that the Tapered Connection can withstand at least 500 thermal cycles between 70°F and 1500°F at 300 psi without risk of fatigue failure. The Tapered Connection also provides, in its 6 in. flange, the gas sample-air pressure-boundary penetrations for the Alumina Heater's mullite-beaded heater lead wires and its thermocouples, which are sealed at the penetrations with Conax fittings. WRP-X-AQ insulation is installed in the remaining gap between Tapered Connection reducers and Spool Piece.

The Throttle and Shutoff subassembly, between Tapered Connection and analyzer, includes two shutoff valves, a throttle valve, and a filter. Also included are tees for measuring gas sample temperatures, to ensure isothermal conditions are being achieved, and taps for backflushing with either steam or gas. A Pressure Letdown is provided to help reduce the sample gas pressure, from the up-to-300 psi gasifier level to the atmospheric analyzer level, by use of pipe friction (rather than by orificing which, with local velocity increases, would reduce local temperature). The Letdown consists of a 7/16 in. OD x 1/16 in. wall x 8 ft long stainless steel tube holding a second 1/4 in. OD plugged tube that is centered by dimples formed in the outer tube. Both tubes are wound into a 7-1/2 in. OD x 12 in. high helix to reduce overall length. The sample gas stream flowing through the annulus between tubes undergoes a significant pressure drop under desired isothermal conditions. The Throttle and Shutoff subassembly components are provided with three separate heaters of 1/8 in. OD sheathed heater wire, and insulated with WRP-X-AQ material. One of the three heaters is dedicated to the valves, which are not allowed to exceed 1200°F.

The Alumina Heater and the Heater Console, Fig. 6, have already been tested together, with the Heater at 1500°F in air, and operated satisfactorily after modest improvements were made. The Heater was originally made with the welds between heater wires and heater lead wires (the latter twice as big in diameter as the former) outside of the alumina bonding cement. This resulted in hot spots in the exposed heater wire at those locations, because the relatively high thermal-conductivity cement was not available to carry the heat away. The Heater was repaired to ensure that the heater wires were completely covered by cement. Also, the heater controllers were originally not provided with variable transformers, the idea being that the controllers' voltage-pulsing capabilities could avoid heater overheating regardless of maximum applied voltage. This did not prove to be the case, so variable transformers were added to allow reducing applied heater voltage.

Also, the Pressure Letdown has been calibrated for pressure drop vs. flowrate, so that it can be used as a gas-sample-stream flowmeter. Unfortunately, the Pressure Letdown was found to produce less pressure drop than desired, primarily because last-minute parts availability necessitated using parts that produced a slightly larger flow annulus than was originally selected. It is not planned to procure an additional higher-pressure-drop device of this type until the first has been tested under prototypic conditions; the device, with its narrow annulus, may tend to plug too readily and have to be re-designed.

INSERTABLE PYROMETER

This component, also with nominal design conditions of 300 psig and 1500°F, is designed to measure radial temperature distributions within a water-cooled coal-process vessel such as the METC low-Btu gasifier. Gasifier temperatures are of interest to METC researchers again because they wish to correlate them with performance of product stream cleanup system components.

Figure 7 illustrates an assembly of a number of subassemblies of the Insertable Pyrometer, namely the Guide Rod and Support Subassembly, the Slide Subassembly, the Probe Subassembly, and a hydraulic cylinder. The reference Probe Subassembly consists of a housing of 1 in., Sch. 160 Incoloy 800 pipe which contains internals the most important of which is a stainless-steel-encased, 1/4 in. dia. quartz rod that extends along the axial centerline of the Probe. The inboard end of the quartz rod receives infrared signals from various radial positions in the gasifier's bed, and the rod transmits the signals to a Vanzetti signal analyzer (not shown) at the outboard end of the Probe.

The actual connection between the quartz rod and the signal analyzer consists of a short length of flexible fiber optics, provided by Vanzetti. The correlation between signal analyzer output and temperature is dependent on the gasifier bed's emissivity at the inboard end of the quartz rod. (The temperature recorder, Fig. 8, has provision for emissivity input.) It is expected that the bed's emissivities are very close to unity; however, even if the emissivities were as low as 0.8 the error in recorded temperatures, assuming $\varepsilon = 1$, would be less than five percent.

It is anticipated that differential thermal expansion, between the quartz and potential deposits from the gasifier bed, may keep the inboard end of the quartz "clean". If not, steam-jet cleaning is a possible backup, as is substitution of a thermocouple(s) for the quartz rod. Potential advantages of the quartz rod over thermocouples are faster time response and longer life. Even though the design temperature of the Probe is "only" 1500°F, it is anticipated that it will be possible to insert its inboard end momentarily to the center of the METC bed, where temperatures as high as 2400°F could be encountered.

A concentric ring is welded to the outboard end of the Probe, and this ring is "trapped" by the Slide Subassembly which rides, courtesy of Thomson ball bushing pillow blocks, on the guide rods of the Guide Rod and Support Subassembly (Fig. 7). The weight of the latter is supported by calibrated-spring hangers. A hydraulic cylinder bolted to the Guide Rod and Support Subassembly has its piston rod bolted to the Slide Subassembly and provides the force necessary to insert the Probe against the gasifier pressure. The Probe is sealed by a Stuffing Box Subassembly, Fig. 9, which uses Garlock graphite packing and is flanged at its inboard end to a bellows Expansion Joint flanged at its own inboard end to an existing 2 in. OD carbon steel nozzle welded to the gasifier water-jacket outer wall. Inboard of the Stuffing Box Subassembly, the Probe slides inside a 1-1/4 in., Sch. 40 Incoloy 800 horizontal pipe that is attached to the inner wall of the water jacket. The outboard end of this pipe is welded to the outboard flange of the Expansion Joint. As with the Non-insertable, Isothermal Gas Sampler, the Expansion Joint is provided with a tap to allow cooling water to circulate from the water jacket, through the nozzle and Expansion Joint, and on to the suction of the water jacket circulating pump.

The Probe insertion load provided by the hydraulic cylinder is borne by the water-jacket nozzle flange, which the Guide Rod and Support Subassembly reacts against. The hydraulic pump for the hydraulic cylinder is shown in Fig. 10. The pump discharge line is provided with a relief valve to prevent excessive load from being exerted on the water-jacket nozzle.

An electro-mechanical position indicator is mounted on the Guide Rod and Support Subassembly. The analog signal from this device, as well as the one from the infrared signal analyzer, is recorded by the unit shown in Fig. 8. Thus one is able to read how gasifier bed temperature varies with radial position, each time the Probe is inserted into the gasifier.

Testing of the Insertable Pyrometer to date has consisted of connecting the hydraulic cylinder, Fig. 7, to its hydraulic pump, Fig. 9, and checking Probe movement under substantial load. The assembly operated satisfactorily. Also, operation of the temperature-position recorder, Fig. 8, was checked, using an infrared calibration source provided by Vanzetti. Again, the system tested operated satisfactorily.

INSERTABLE, COMBINED, HIGH-VELOCITY THERMOCOUPLE AND ISOTHERMAL GAS SAMPLER

This "ICHVT & IG Sampler" combines the isothermal gas sampling and high-velocity-thermocouple capability of the Non-insertable, Isothermal Gas Sampler with the insertion capability of the Insertable Pyrometer. In fact, development of the latter two devices deliberately preceded that of the former, so that its potential problems could be divided into roughly two parts for parallel efforts toward solving them. Thus, the Alumina Heater, Expansion Joint, Tapered Connection, Throttle and Shutoff Subassembly, Pressure Letdown, and Heater Console of the Non-insertable, Isothermal Gas Sampler, and the Probe, Guide Rod and Support Subassembly, hydraulic cylinder and pump, Slide Subassembly, and Stuffing Box Subassembly of the Insertable Pyrometer all have their direct counterparts in the ICHVT & IG Sampler.

Specific differences between the present sampler and its two predecessors follow:

1. The high-velocity thermocouple is 1/4 in. OD rather than 1/16 in., to allow a 4x thicker sheath and correspondingly increased sulfidation resistance. Also, the heater wires are 17 ga. rather than 20 ga., for the same reason. The spider-centered 1/4 in. OD thermocouple runs the entire length of the alumina sample-gas tube, which is accordingly 5/8 in. OD x 1/2 in. ID.

2. To accommodate the alumina tube, heater wires, control and limit thermocouples, and thermal insulation, the Probe is 2 in. dia. instead of 1-1/4 in., requiring that a new 3-1/2 in. nozzle be installed on the METC gasifier water jacket.

3. The Slide Subassembly is connected to the Probe simply by being bolted with the Tapered Connection flange bolts. (The Tapered Connection, and Throttle and Shutoff Subassembly are parts of the Probe.)

4. Differential thermal expansion between the pipes attached to the gasifier water-jacket inner and outer walls (the former pipe being that which the Probe slides through, and the latter that to which the nozzle flange is welded) is accommodated by an O-ring-sealed slip joint rather than by a bellows expansion joint. However, the spool piece holding the O-ring can be replaced by a standard bellows joint of equal length if the O-ring should prove unsatisfactory.

5. The current intention is that the gas analyzer remain stationary while the Probe is moving. Therefore, the Throttle and Shutoff Subassembly are connected to the analyzer with a flexible metal hose that is equipped with heaters and covered with thermal insulation.

There are two possible ways to seal the insertable heated probe of the ICHVT & IG Sampler. First, a sliding seal could be made directly against the heated probe; this seal can be called a "high-temperature seal." Second, a sliding seal (a "low-temperature seal") could be made against a cooled connection welded to the heated probe. An early tradeoff study had resulted in selection of the "low-temp. seal" approach, because uncertainties concerning performance of a "high-temp. seal" were believed to be too great to face. However, as time passed two additional significant things were learned. First, tests on the Alumina Heater for the Non-insertable Isothermal Gas Sampler had shown that a compact heated probe can be built with enough internal insulation to keep a "high-temp. seal" from actually becoming very hot; this eliminated the main concern over that design approach. Second, detailed calculations for the "low-temp. seal" design had shown that it was difficult to provide for the high insertion force (14,000 lb) required for that design, especially when considering shock loads that might result from hydraulic line failure. (The insertion force for the "high-temp. seal" design is only 1800 lb.) Accordingly, a second tradeoff study was made, and results from that led to eventual selection of the "high-temp. seal" version of the sampler design.

The ICHVT & IG Sampler design has been completed, and this component is currently being fabricated.

CORING-TYPE SOLIDS SAMPLER

This component is designed to take core samples from the interior of a water-cooled coal-process vessel, such as the low-Btu METC gasifier, and allow the samples to be transported in a "bomb" to a laboratory for analysis. The purpose of such analyses is to increase understanding of how coal lumps or particles change size and composition as they move from the feed end to the discharge end of the vessel.

A one-end-open tube with saw-tooth leading edge is inserted radially into the vessel interior, and rotated simultaneously, the insertion being accomplished by hydraulic force and the rotation manually, at least in the initial version. Material inside the vessel is thereby trapped inside the tube, in roughly the same relative position as when undisturbed. The tube is then withdrawn from the vessel, carrying the trapped material with it as aided by ratchet-type lugs at the tube open end. The tube is withdrawn through a nozzle flanged to two open ball valves which are flanged to each other. When the sample tube is past the valves, they are closed and the flanged connection between them is broken to allow removal of the sample to a laboratory.* The outboard ball valve is piped to a stuffing box which seals the outboard end of the sample tube. The sample tube is equipped with extension pieces which must be added during sample-tube insertion, and removed during sample-tube withdrawal. This provision permits substantial reduction of the overall length of the complete sampler, but of course increases the complexity of taking a sample.

The conceptual design of the Coring-type Solids Sampler has been completed. At present there are no plans for proceeding further with this component.

FURTHER TESTING

Originally it was planned to perform the initial prototypic testing, or use, of the first three samplers described here with the METC gasifier itself. However, that facility is only operated several weeks each year and during that limited time it must operate very reliably in order to serve its main purpose of providing a product stream for testing of cleanup equipment. Because testing or use of the samplers at their present stage might decrease the gasifier reliability, it has been decided to

---

*Chemical quench to halt the reactions is possible.

"debug" the samplers with the METC "dirty gas generator." The start of such testing has not yet been scheduled.

SUMMARY

Several components for sampling contents of water-cooled coal-process vessels operating under high temperatures and pressures have been designed and built or are under fabrication. Initial testing has been completed with satisfactory results. However, much more rigorous testing is required before the samplers will have proven themselves to be useful devices for aiding development of commercial plants for enhanced coal utilization.

ACKNOWLEDGMENTS

The helpful advice and cooperation of METC are gratefully acknowledged, especially those of Messrs. J. J. Kovach (technical monitor), K. Pater, P. Bekowies, and R. V. Rahfuse. Thanks are also especially due to the following ANL personnel and their participating colleagues: N. R. Carlson, J. G. Daley, and C. B. Kinsella (Components Technology), J. M. Paul (Electronics), F. A. Simon (Central Shops), C. Lenz and T. E. Kaiser (Engineering), and C. B. Chapman (Procurement); and to student aides R. D. Frazier and W. M. Adamski (Univs. of Evansville and South Florida, respectively).

REFERENCES

1. S. M. Csicsery, et al., "Catalyst and Gas Samplers for Fluid Catalytic Cracker Regenerator," Ind. Eng. Chem., Process. Des. Develop., 14:1, 93-96 (1975).

2. W. Szwab, W. H. Fischer, and B. N. Murthy, "Technical Support for Coal Conversion and Utilization: Techniques for Particulate Sampling and Measurement from Gasifiers at High Temperature and High Pressure," FE-2200-5 (Dec 1976).

3. A. J. Liberatore and D. W. Gillmore, "Behavior of Caking Coals in Fixed-bed Gasifiers," CONF-750868-1 (Aug 1975).

4. H. F. Mullikin, "Gas-temperature Measurement and the High-Velocity Thermocouple," in "Temperature - Its Measurement and Control in Science and Industry," Reinhold, New York, 1941, p. 775 ff.

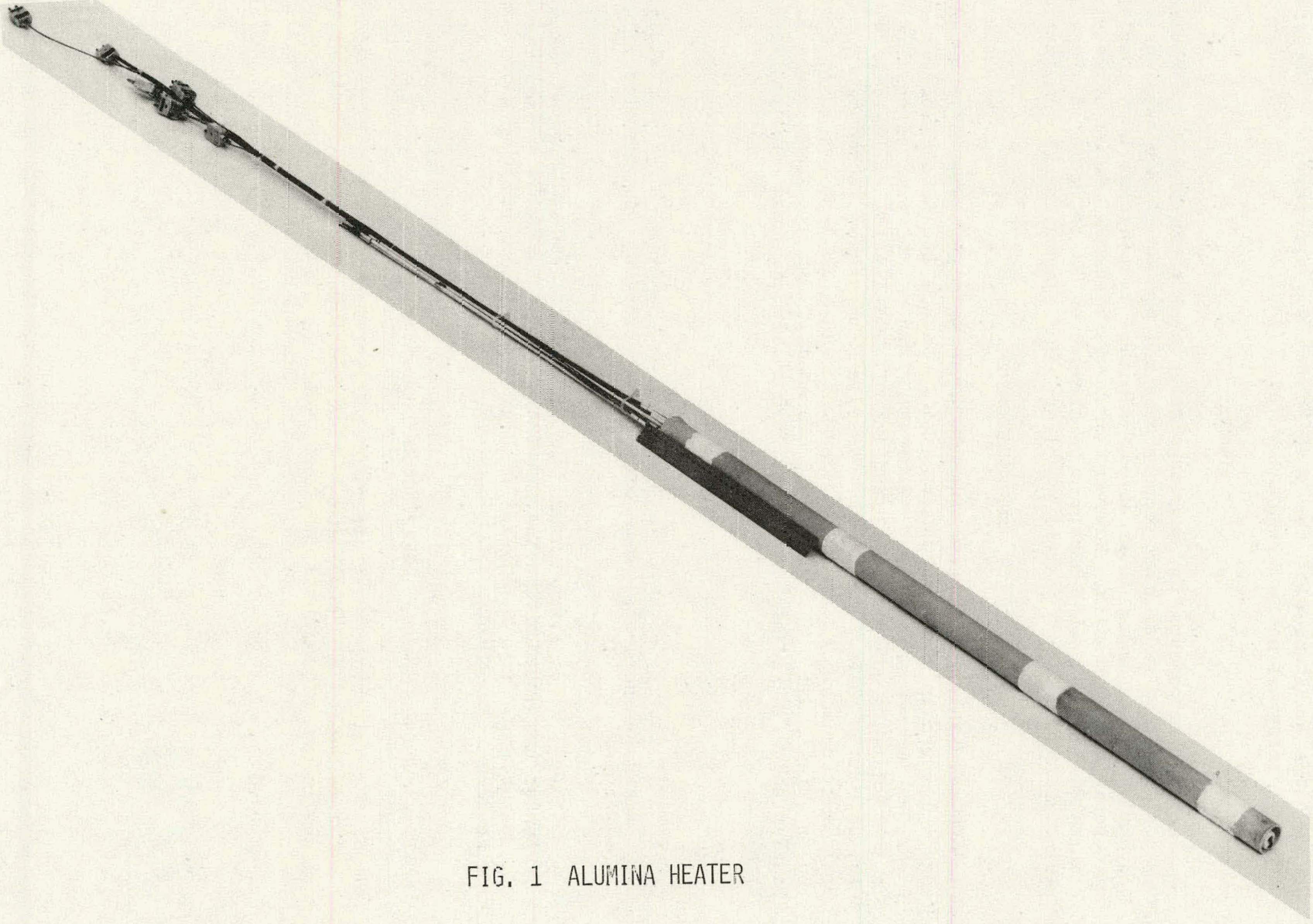


FIG. 1 ALUMINA HEATER

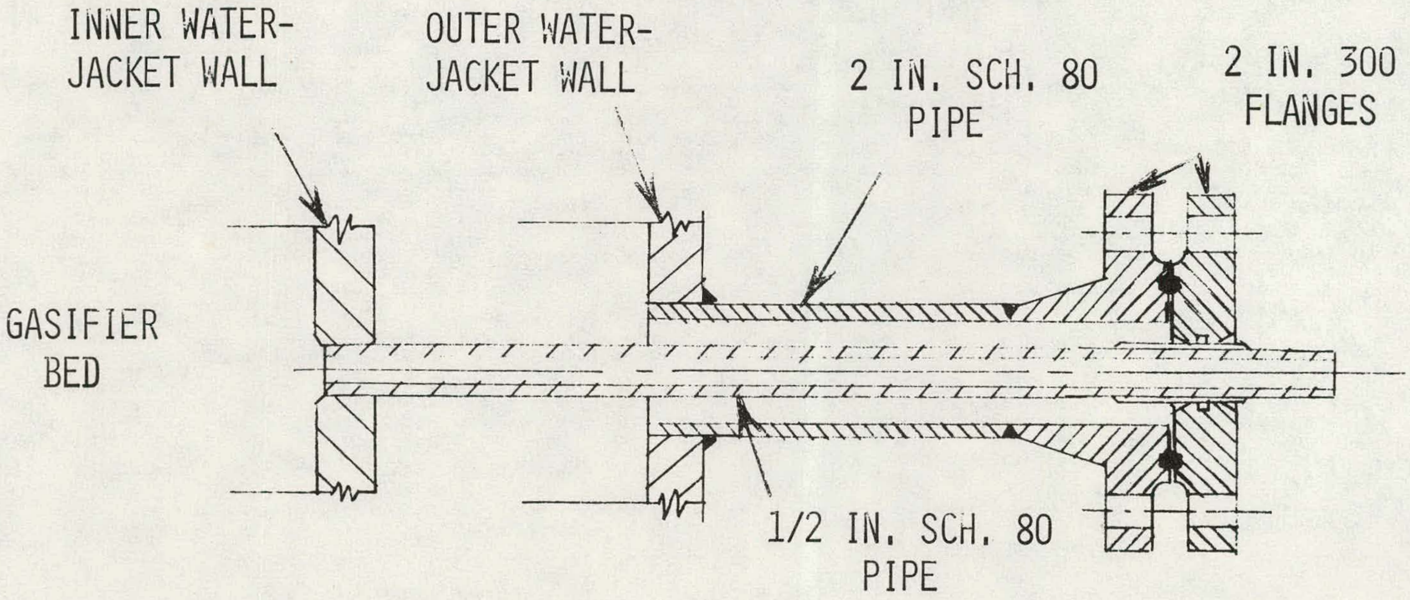


FIG. 2 EXISTING METC GASIFIER NOZZLE (TYPICAL)

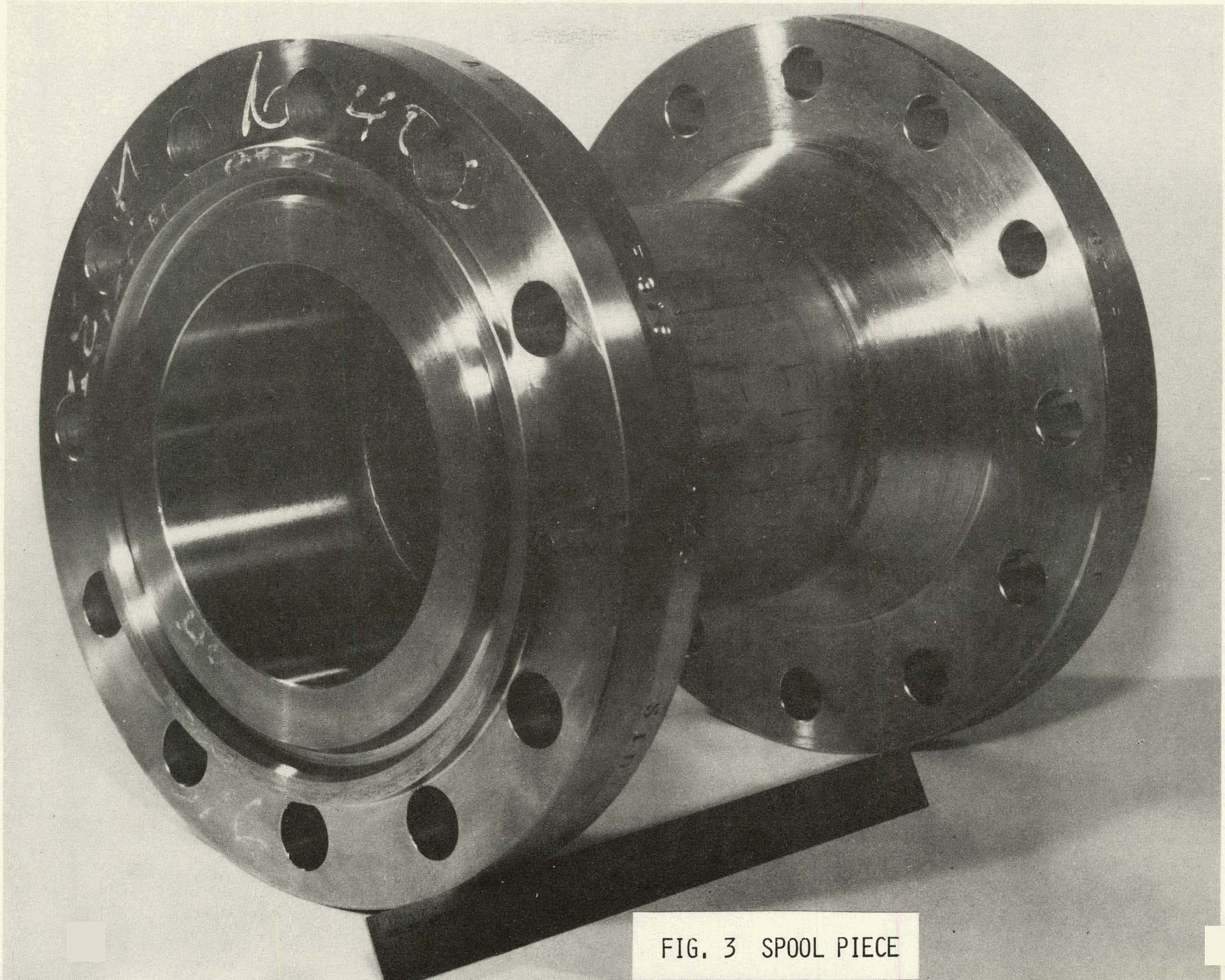


FIG. 3 SPOOL PIECE

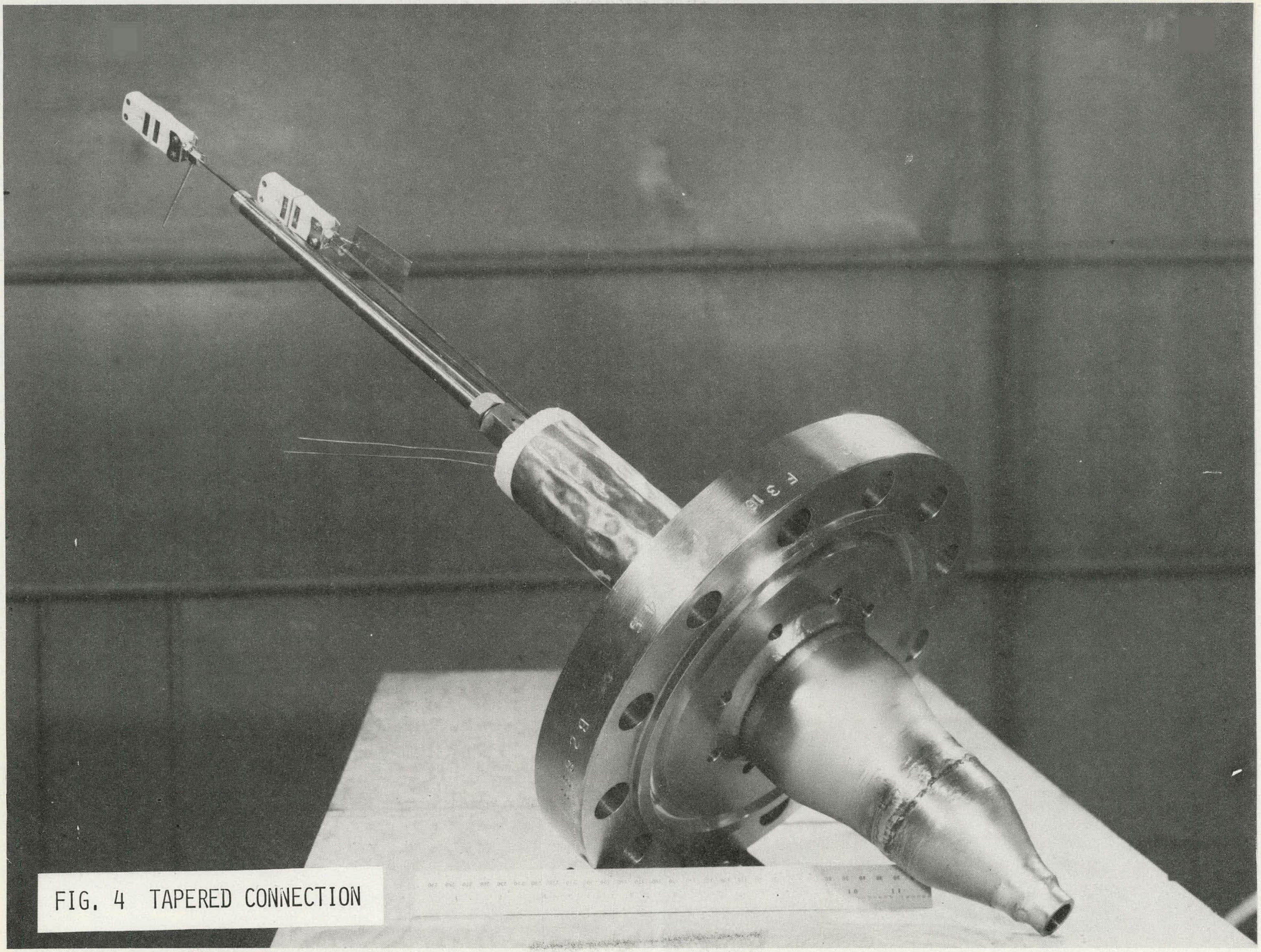


FIG. 4 TAPERED CONNECTION

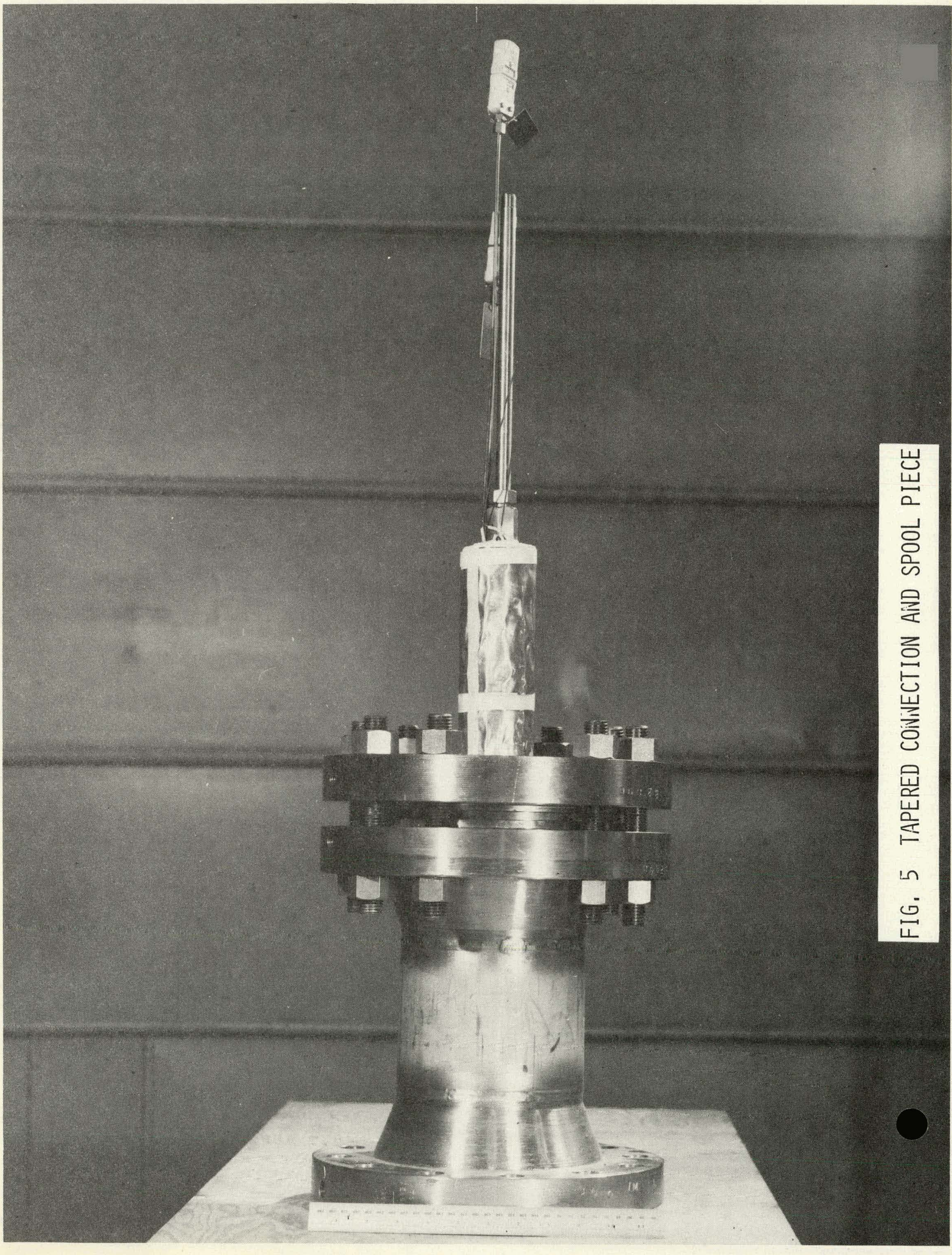


FIG. 5 TAPERED CONNECTION AND SPOOL PIECE

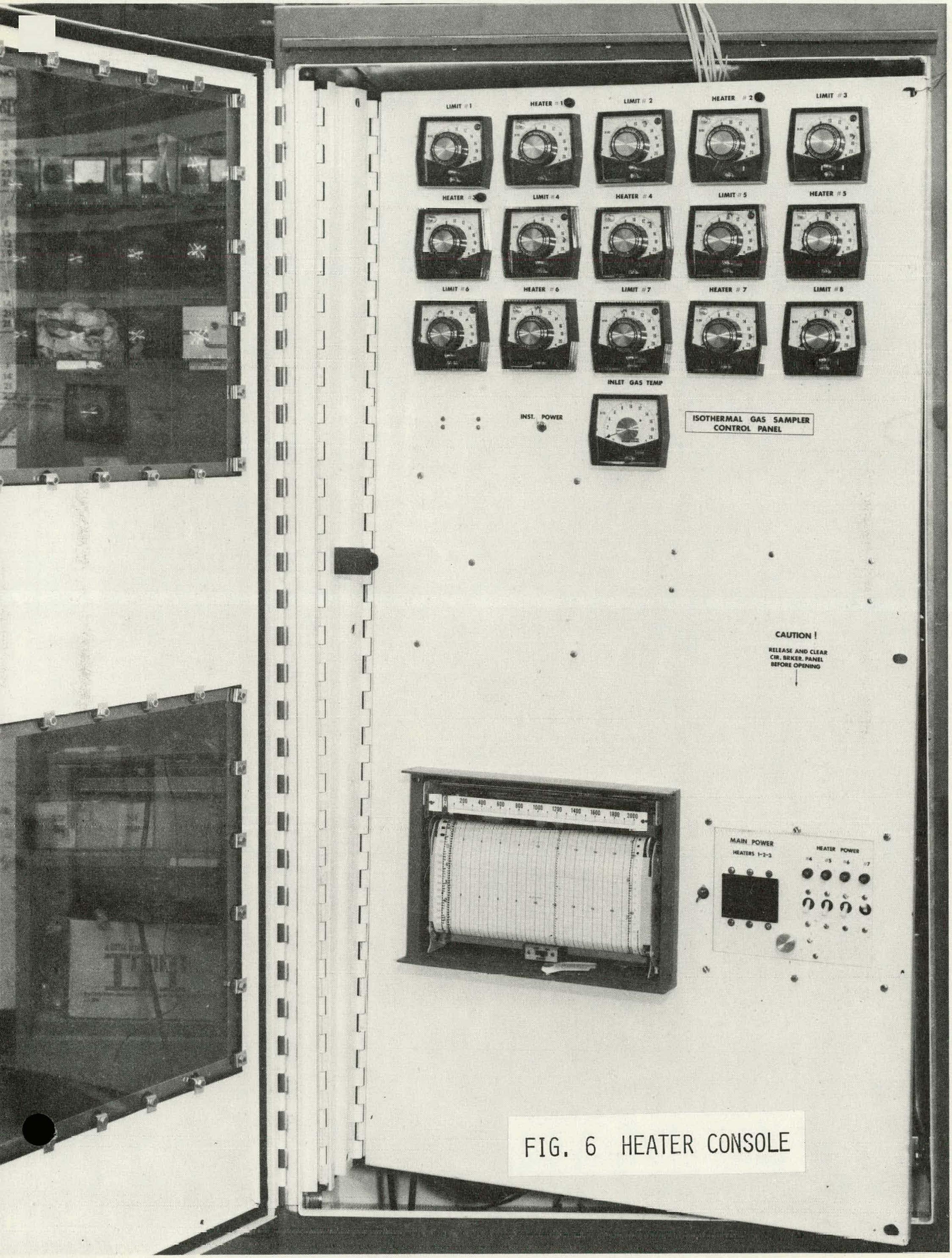


FIG. 6 HEATER CONSOLE

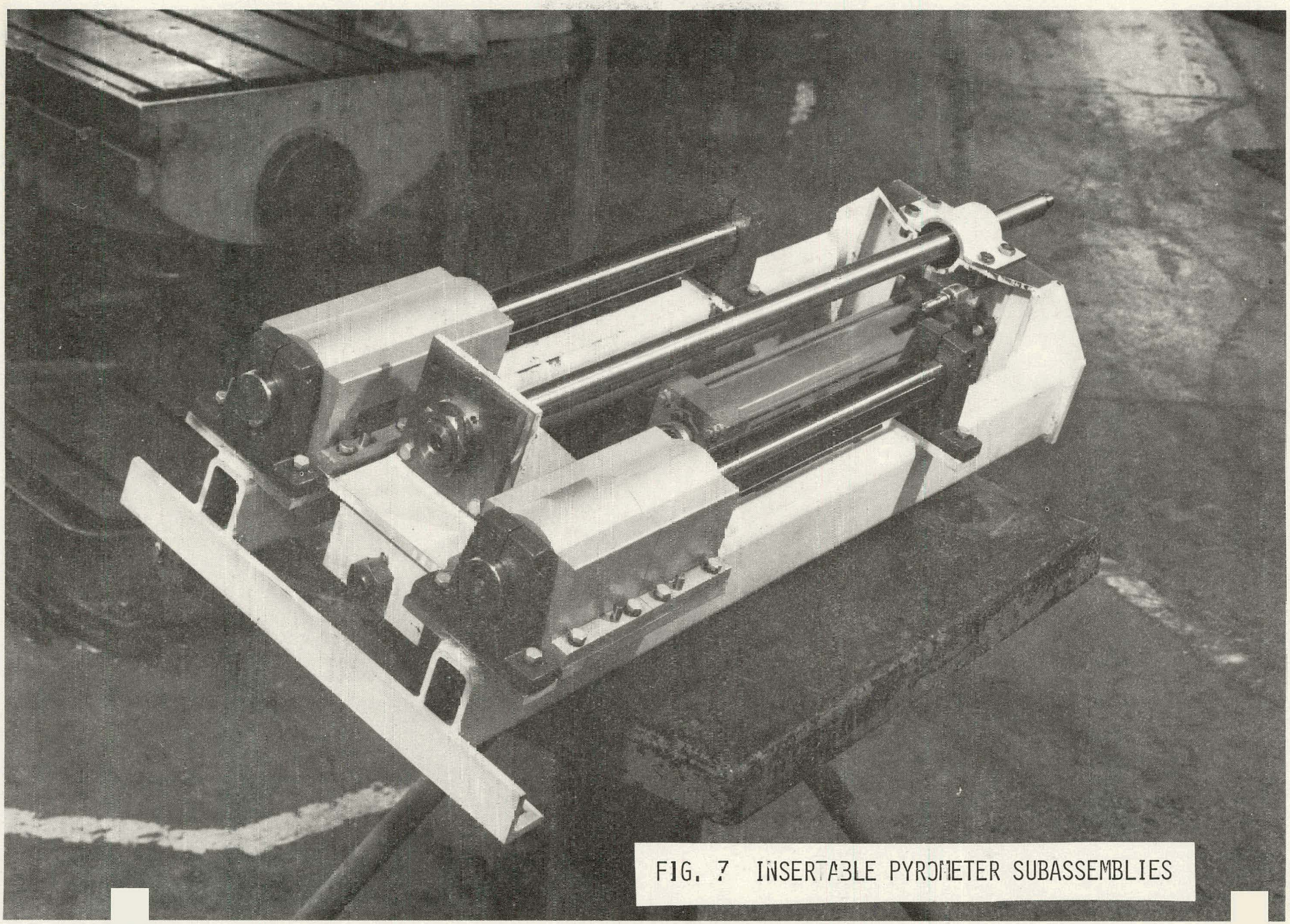


FIG. 7 INSERTABLE PYROMETER SUBASSEMBLIES

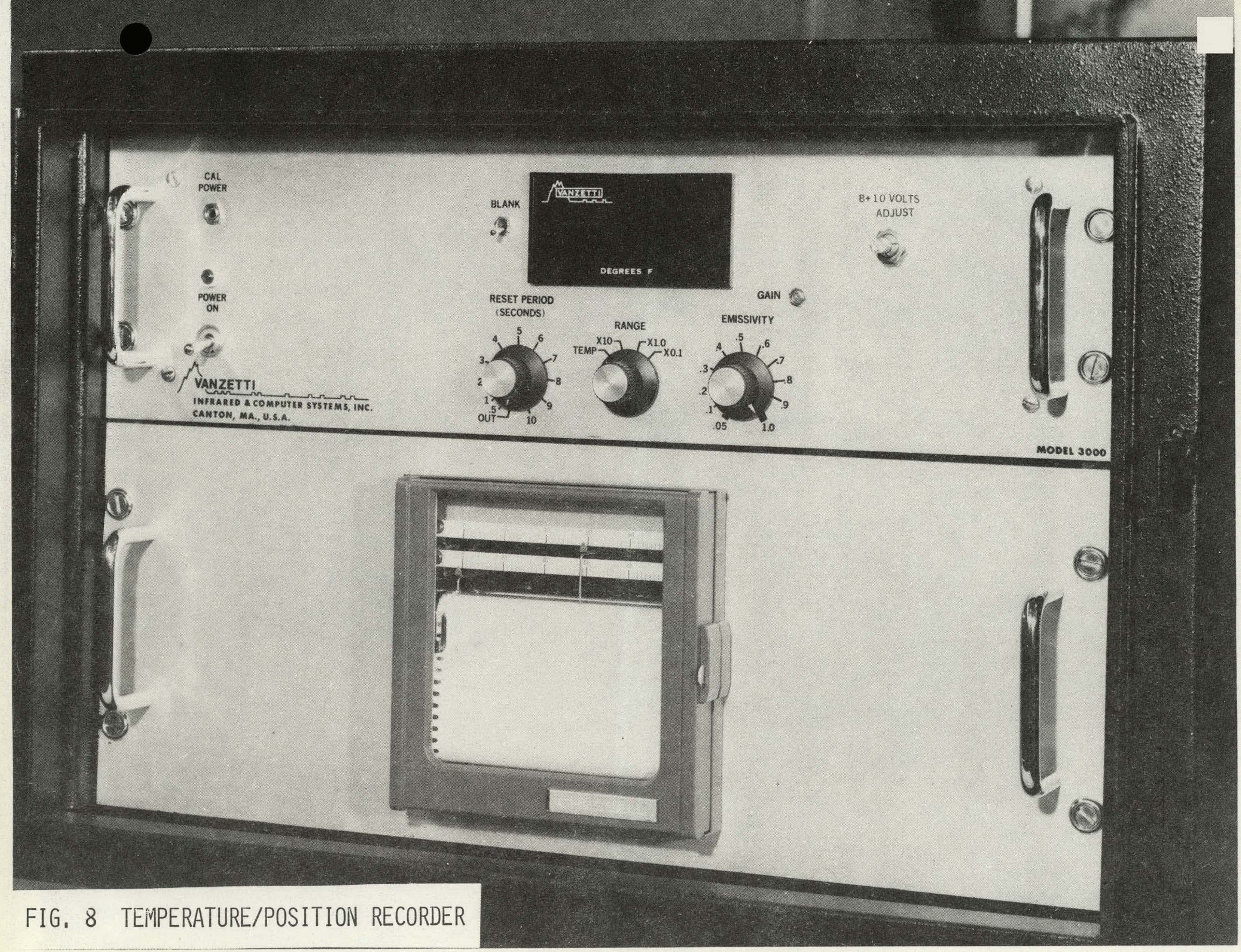


FIG. 8 TEMPERATURE/POSITION RECORDER

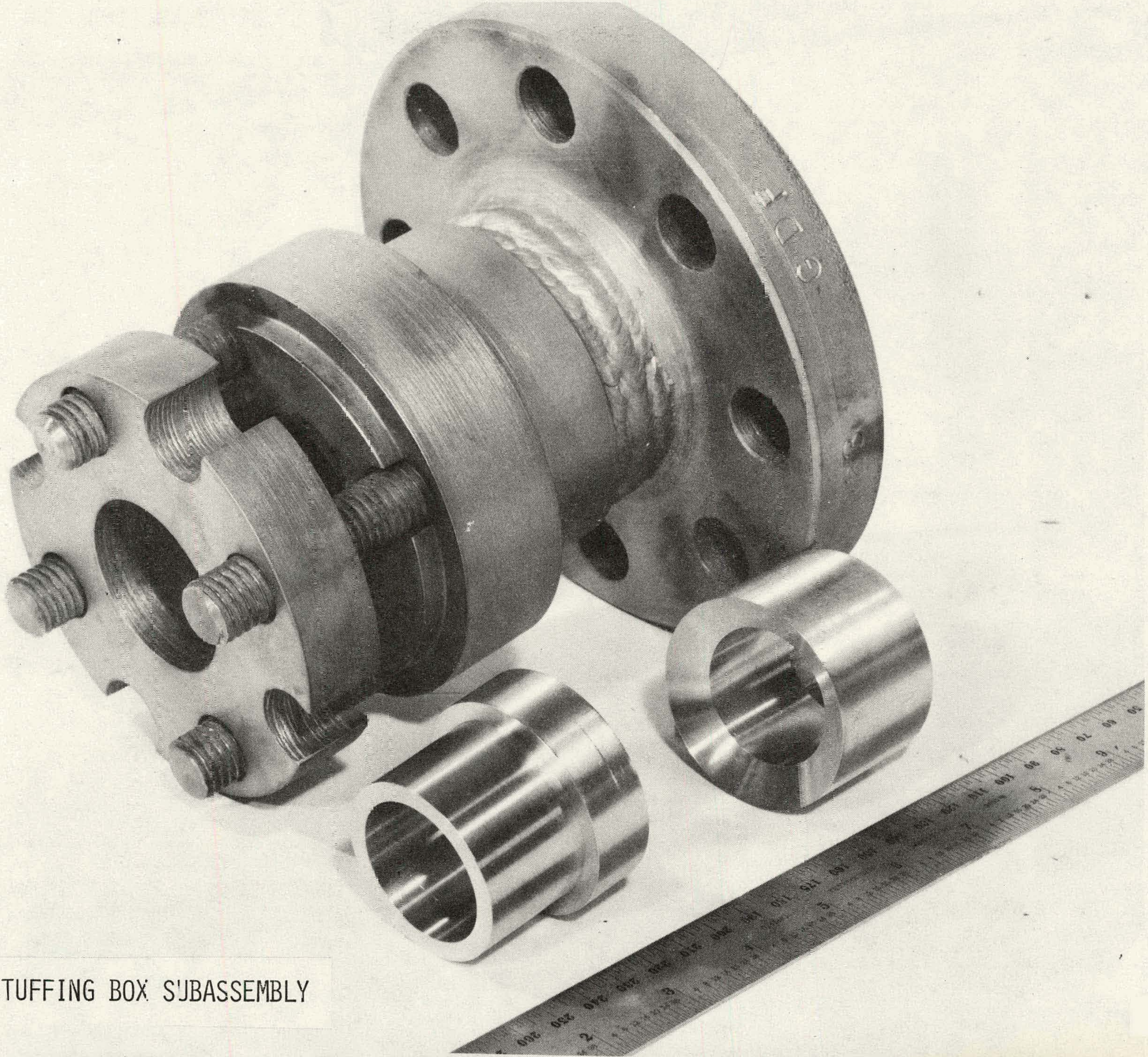
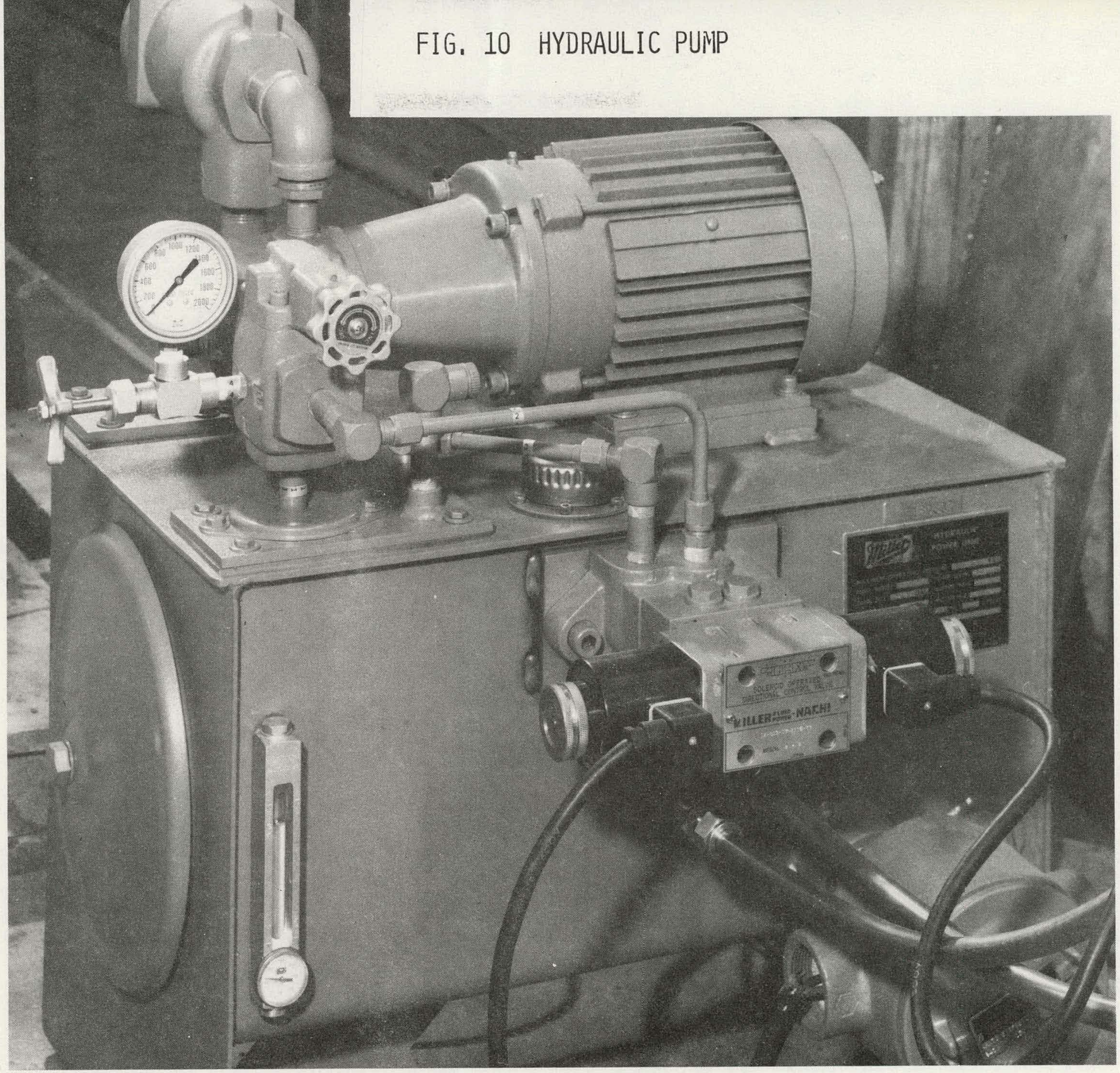


FIG 9 STUFFING BOX SUBASSEMBLY

FIG. 10 HYDRAULIC PUMP



A PORTABLE FLUOROMETRIC MONITOR TO DETECT POLYNUCLEAR AROMATIC HYDROCARBON CONTAMINATION OF WORK AREA SURFACES*

Daniel D. Schuresko
Chemical Technology Division
Oak Ridge National Laboratory
Oak Ridge, Tennessee 37830

To be presented at the 1979 Symposium on Instrumentation and Control for Fossil Energy Processes, Denver, Colorado, August 20-22, 1979.

---

*Research sponsored by the Office of Health and Environmental Research and the Office of Fossil Energy, U. S. Department of Energy under contract W-7405-eng-26 with the Union Carbide Corporation.

A PORTABLE FLUOROMETRIC MONITOR TO DETECT POLYNUCLEAR AROMATIC HYDROCARBON CONTAMINATION OF WORK AREA SURFACES

Daniel D. Schuresko
Chemical Technology Division
Oak Ridge National Laboratory
Oak Ridge, Tennessee 37830

ABSTRACT

A hand-held fluorometric monitor for detection of surface contamination by polynuclear aromatic (PNA) compounds is described. The instrument will indicate the presence of microgram quantities of PNA in the workplace at distances ≤ 1 m. Laboratory test data using coal liquefaction products and wastes are presented. It is anticipated that this type of "spotter" will be used extensively to monitor PNA contamination of the "clean" areas of coal conversion facilities such as lunch rooms, shops, changing facilities, and control rooms. Actual field evaluation of two spotter units at several coal conversion pilot plants is scheduled to begin during FY 1980.

INTRODUCTION

Uptake of polynuclear aromatic (PNA) compounds via contact with contaminated surfaces in the workplace has been identified as a major mode of worker exposure.[1] Thus, the need for instrumentation to monitor PNA buildup on workplace surfaces (e.g., the result of aerosol condensation) has been recognized.[1,2] Such instrumentation must be capable of: (1) functioning during actual plant operation in varied working environments; (2) detecting material spilled on various work surfaces such as machinery, plumbing, construction materials, and on personnel and clothing; and (3) being easily and reliably operated by all plant personnel.

The fluorescence spotter described in this paper* has these capabilities. This instrument, which consists of a hand-held optics unit connected via an umbilical cable to an electronics module (Fig. 1), enables remote monitoring of work area surfaces at distances ≤ 1 m. The electronics module, which

---

*U.S. Patent applied for.

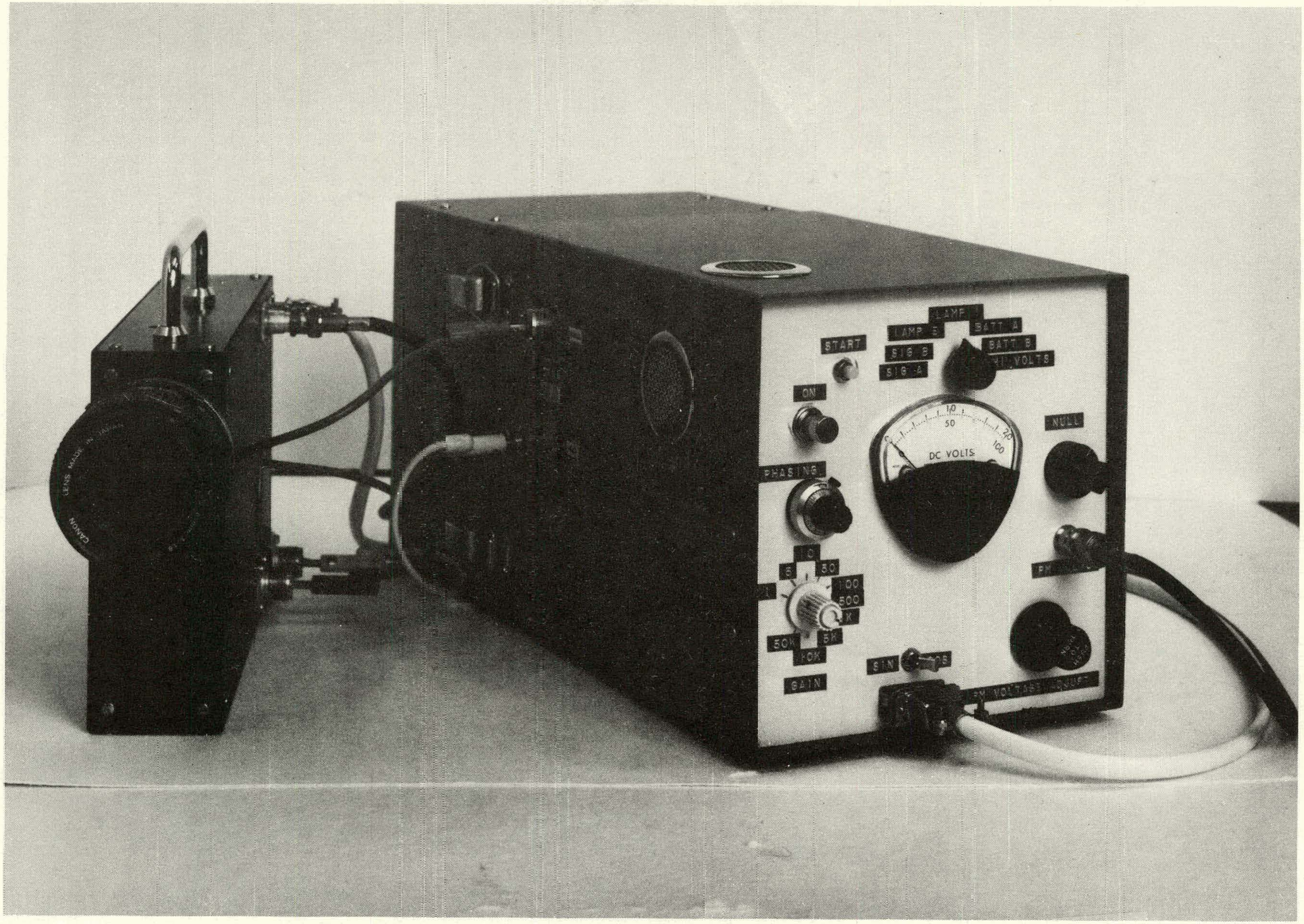


Fig. 1. Portable fluorescence spotter.

normally operates with ac power, can also be operated on rechargeable batteries; thus the entire instrument, including the battery pack, is portable.

It is anticipated that portable fluorescence spotters will be used extensively to detect surface contamination in changing areas, lunch rooms, shops, control rooms, and other "clean" areas in coal conversion facilities, and to monitor skin contamination of coal plant workers. The currently used method of detecting contamination is to turn off ambient lighting and scan the suspected area with a black light. In contrast, the newly developed spotter (1) can be operated outdoors in direct sunlight or indoors in the presence of strong background illumination; (2) provides a quantitative measure of the amount of fluorescent material; (3) discriminates between the fluorescence of organic materials and some inorganic compounds based on their fluorescence lifetimes; and (4) does not present a vision hazard to personnel.

EXPERIMENTAL

The spotter induces and detects the fluorescence of PNAs that characteristically absorb light in the 350- to 440-nm region of the spectrum and fluoresce with high efficiency in the blue-green region of the spectrum. Multiring heteroatom aromatic compounds, including arcidines, are also detected, although they generally absorb light and fluoresce at longer wavelengths than do their pure hydrocarbon counterparts.

The optics unit, shown schematically in Fig. 2 serves two functions. It is (1) an illuminator, which produces a beam of amplitude-modulated fluorescence-exciting light; and (2) a fluorescence detector, which responds to filter-selected wavelengths bands in the 380- to 600-nm range. The fluorescence-exciting light is one of the emission bands produced by a high-pressure mercury arc lamp, typically the 365-nm band for PNAs. The lamp output is focused onto vanes of a fixed frequency electromagnetic chopper and subsequently is collimated and filtered. This beam is reflected from an aluminized mirror (reflectance = 96%) and is then focused onto a dichromatic beam splitter appropriate to the selected excitation and emission wavelength bands. The reflected excitation beam is output via a telephoto objective lens that can be adjusted to give the desired excitation beam divergence. When

ORNL DWG 78-17791R

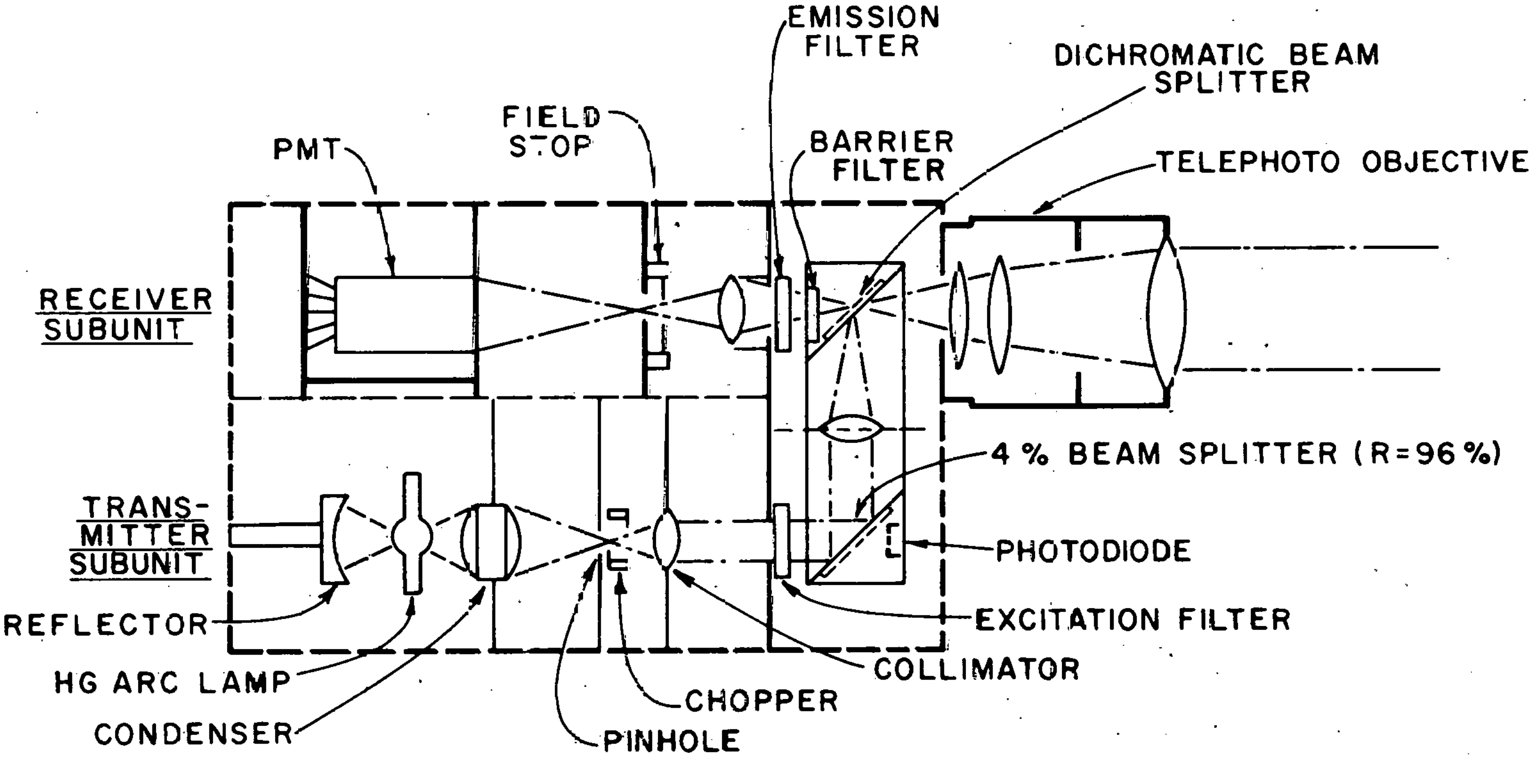


Fig. 2. Spotter optics unit.

the telephoto lens is adjusted to produce a collimated excitation beam, the beam diameter is $\sim$1.55 cm. The 96% reflector passes a small percentage of the excitation beam which is measured by an integrated photodiode/operational amplifier. This signal is used to offset the photomultiplier signal component due to beam splitter and telephoto fluorescence, and to normalize the resultant fluorescence signal by the excitation beam intensity. Sample fluorescence is collected by the telephoto objective, transmitted through the dichromatic splitter, filtered, and subsequently transmitted to the photomultiplier tube, which converts the fluorescence emission into a photocurrent.

The operation of the spotter is depicted in Fig. 3, as are the signal traces corresponding to the radiated uv intensity (trace A) and to the fluorescence (trace B) that is produced when a spill has been "sighted." The radiated uv beam is amplitude modulated at 1 kHz by the electromagnetic chopper; thus the induced fluorescence is also modulated at 1 kHz. This 1 kHz fluorescence signal is superimposed on a much stronger signal from reflected background illumination of the viewed surface. The electronic frequency spectrum of ac-powered fluorescent or incandescent room lighting consists of a 120-Hz frequency component and its harmonics superimposed on white noise (dc-powered lamps and sunlight produce only white-noise background); hence, it is possible to separate the fluorescence signal from the background signal by electronic filtering (trace C). Demodulating and low-pass filtering of this signal (trace D) effectively averages each 1/2-msec pulse and allows detection of fluorescence only 3% as intense as the background illumination in the optical wavelength band of interest.

The signal processing circuitry is schematized in Fig. 4. The photocurrents of both photodetectors are converted to voltages by current preamplifiers, and the two signals are subsequently fed to a differential amplifier. During spotter operation, the null potentiometer is adjusted to produce the minimum digital meter output with the spotter head pointed at an infinitely distant surface. This difference signal is fed to a phase-sensitive demodulator that is gated by a reference signal from the beam chopper oscillator. The output voltages from the demodulator card, which are the sine and cosine phase components of the difference signal, are either routed directly to a three-position output selector switch or are processed by analog circuitry which computes the difference signal amplitude as the square root of the sum of the

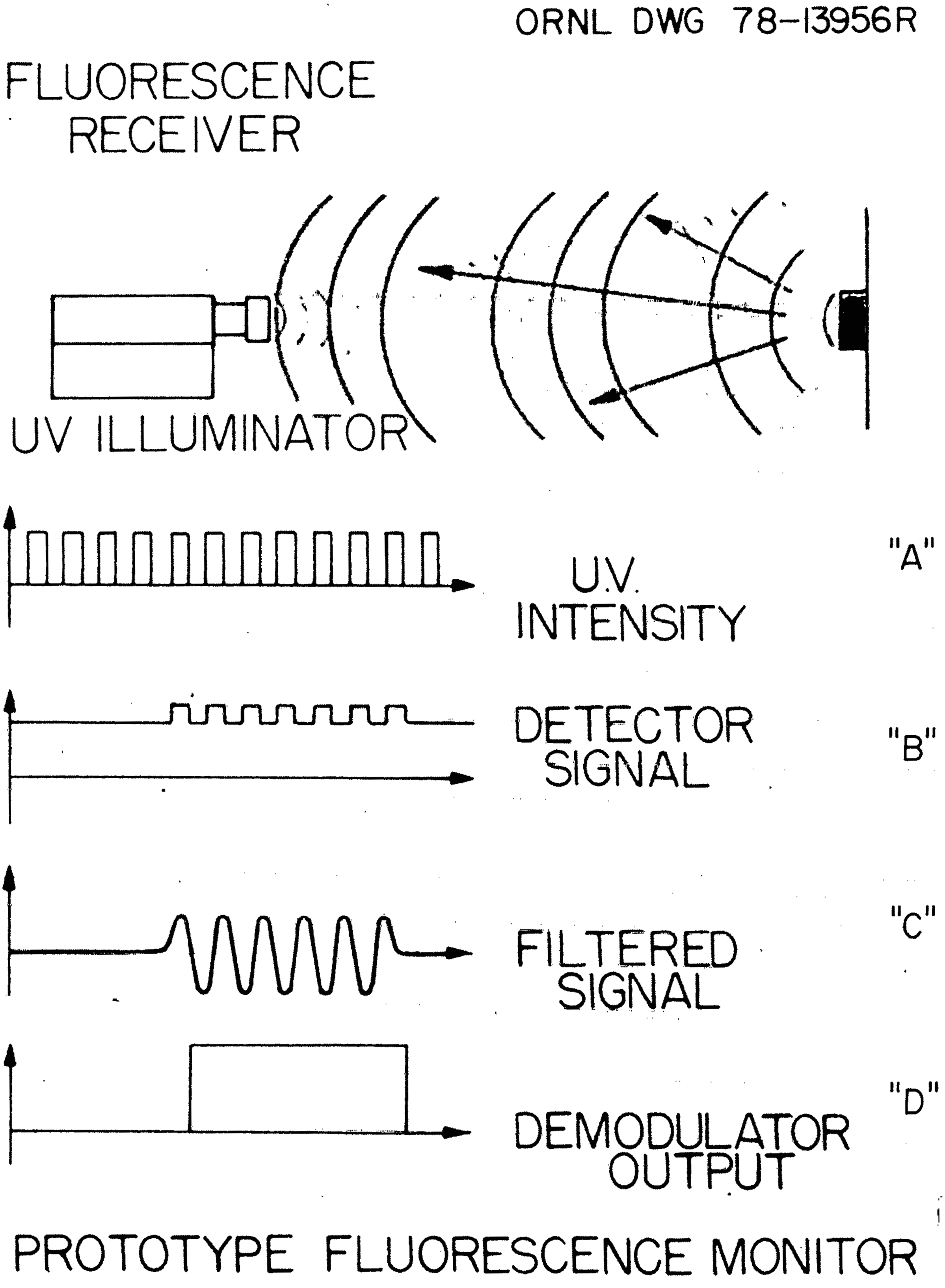


Fig. 3. Principle of operation of spotter.

ORNL DWG 79-1260

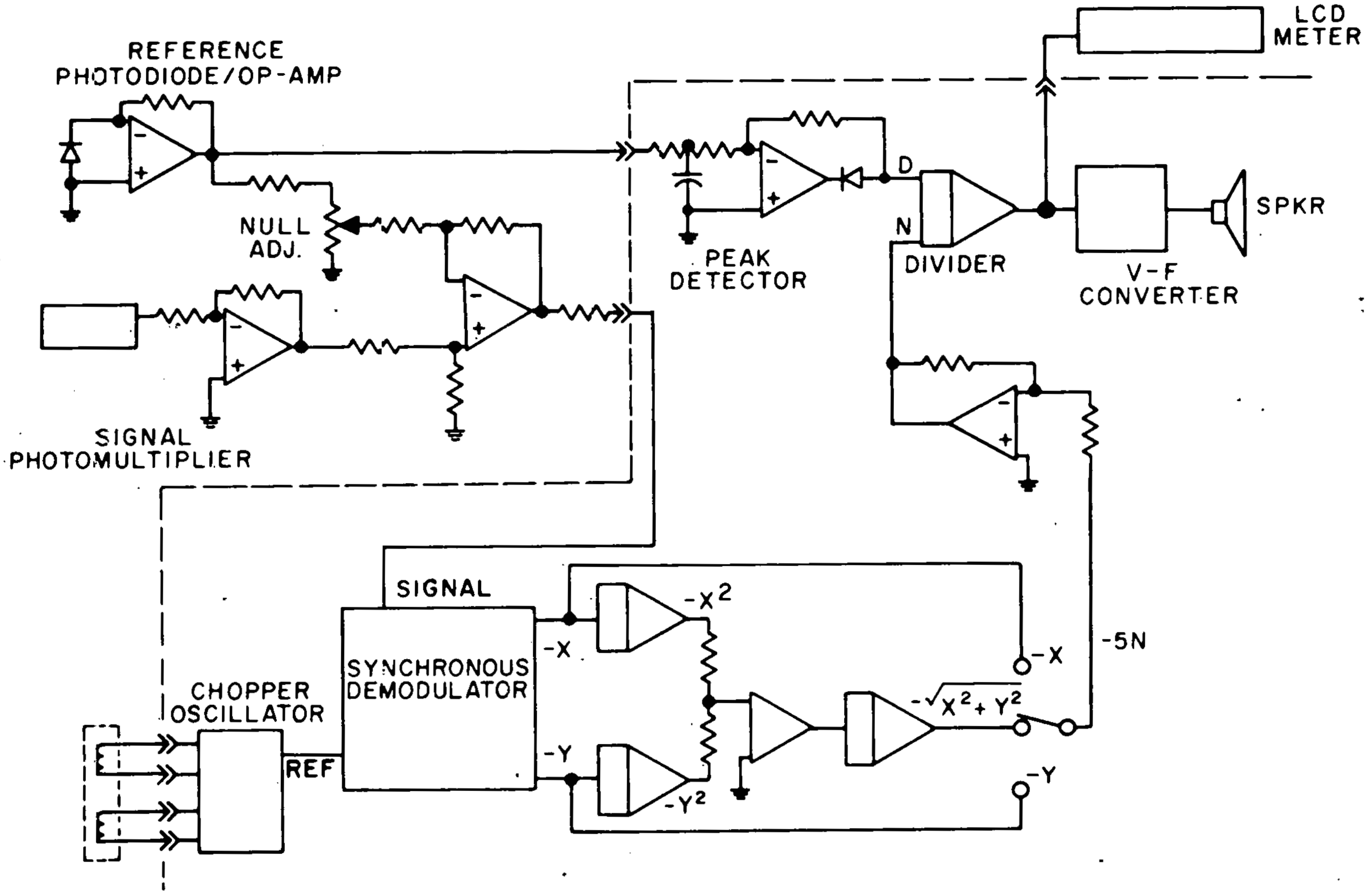


Fig. 4. Spotter signal processing circuitry.

squares of the two phase-components. The selected output is then inverted and fed into the numerator input of an analog divider. The dc-voltage output of the peak detector circuit, which measures the height of the excitation intensity pulses, feeds the denominator input of the divider, whose output is now independent of the mercury lamp output power. This voltage, which has now been compensated for background fluorescence and excitation intensity variation, is read out via a voltage-to-frequency converter coupled to a small speaker and a digital voltmeter. In actual operation, the user scans the suspect surface with the optics head and, upon locating an area that produces a significant increase in the frequency of the audio output tone, reads the voltage level on the meter. Precalibration of the instrument with a known standard enables conversion of the meter voltages to contamination levels in equivalent units of the standard compound.

RESULTS AND DISCUSSION

The spotter has been laboratory tested with pure compounds and with several coal and oil shale products and wastes. When operated in a laboratory area illuminated by fluorescent lighting, the spotter can typically detect 0.1 μg of perylene (as a dilute solution in cyclohexane) at a distance of 50 cm. Considering that 10-μg doses of several PNAs will induce changes in the metabolism of cultured mammalian cells,[3,4] it is evident that the high sensitivity of the spotter is appropriate to its intended task.

The dynamic range of the spotter's response is 0.1 to >10 μg of perylene (at a distance of 50 cm), as shown in Fig. 5. The distance dependence of the signal from a 10-μg sample is shown in Fig. 6 for the condition where the telephoto output lens is adjusted to produce a collimated uv beam. The signal decrease below the (distance)$^{-2}$-power law at distances beyond 60 cm is due to some residual divergence of the uv beam, a result of the finite size of the beam focus on the dichromatic splitter.

Tables 1 and 2 list the spotter-measured specific fluorescence of several synthetic fuel products and wastes. The oil samples were prepared by placing 1- to 10-mg droplets of each oil onto microscope slides and covering each droplet with a cover slip. This technique yielded 1- to 20-μm-thick films of known area and thickness whose optical absorbance at 365 nm, the principal

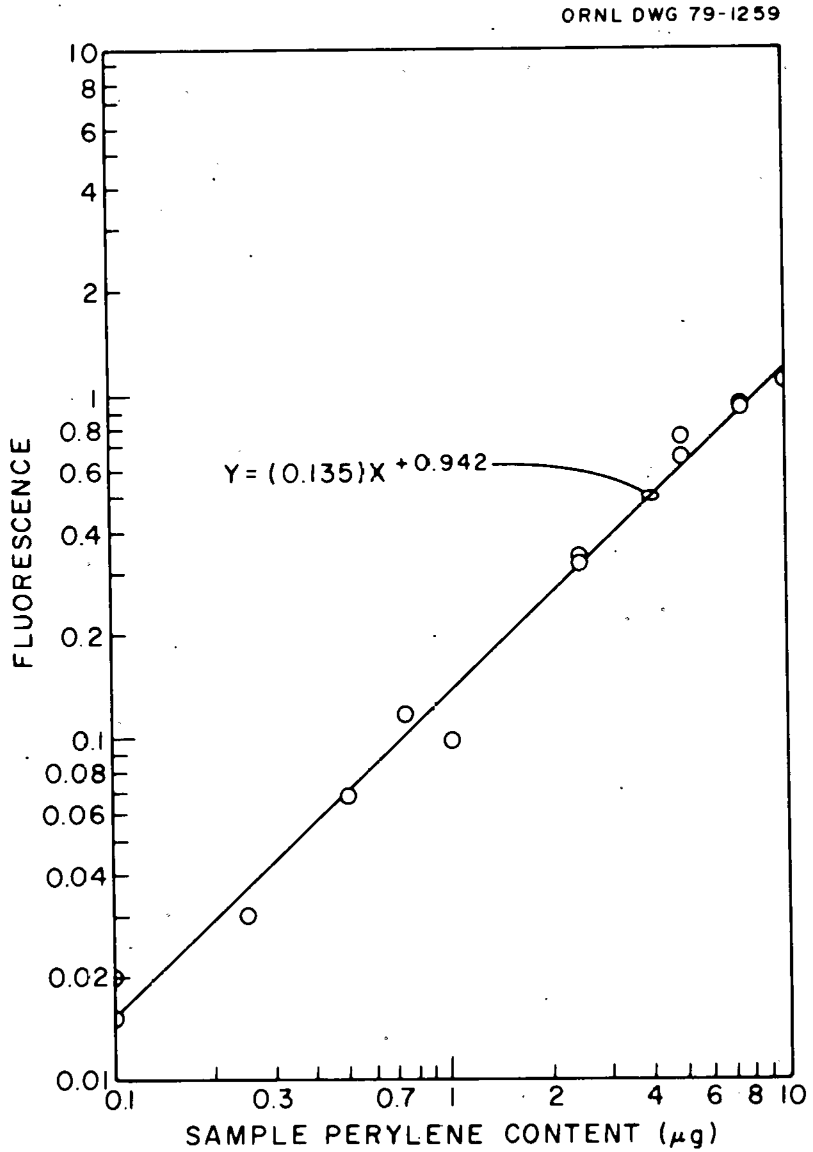


Fig. 5. Spotter response vs sample PNA content. The samples were 0.064 to 6.4 ppm solutions of perylene in cyclohexane.

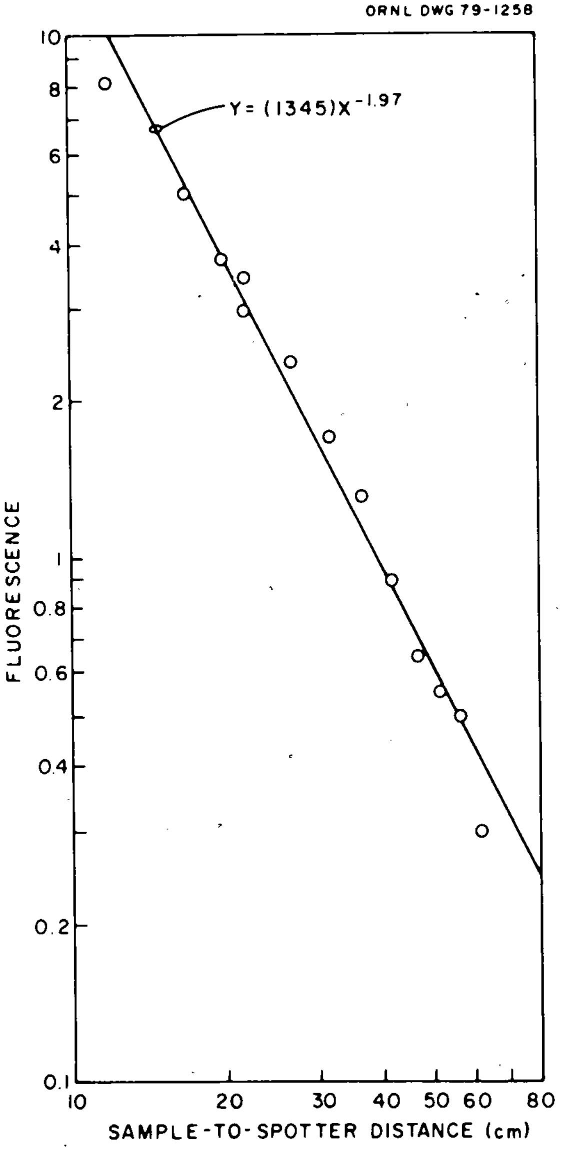


Fig. 6. Distance dependence of spotter response.

Table 1. Specific fluorescence of coal liquefaction and oil shale products

Sample	Specific fluorescence[a] (units/mg)
COED Syncrude	6.3
Hydrotreated coal distillate	3.4
Product distillate	11.3
Centrifuged shale oil	4.8
ORNL hydrocarbonization oil (HC-12)	0.2
SRC-II fuel oil blend	7.7
SRC-I recycle solvent (raw)	4.6
SRC-I wash solvent	0.9
SRC-I light organic liquid (raw)	0.1
SRC-I process solvent	3.7
SRC-I light oil	b

[a] One unit of fluorescence is defined as the equivalent fluorescence of 1 μg of perylene in a dilute solution in cyclohexane.

[b] Not detectable.

Table 2. Specific fluorescence of coal liquefaction wastes

Sample	Specific fluorescence[a] (units/mg)
SRC-I bio-unit feed	0.7×10^{-3}
SRC-I bio-unit effluent	0.4×10^{-3}
SRC-I bio-unit sludge	1.9×10^{-3}
SRC-I plant effluent	b
SRC-I surge tank sludge (diluted 400:1 in cyclohexane)	12.9×10^{-3}
SRC-I surge reservoir water	0.7×10^{-3}
SRC-I graver effluent	0.6×10^{-3}

[a] One unit of fluorescence is defined as the equivalent fluorescence of 1 μg of perylene in a dilute solution in cyclohexane.

[b] Not detectable.

excitation wavelength, was less than 0.3-o.d. units. The undiluted waste samples were placed into 3.6-cc vials for measurement, with the exception of the surge-tank sludge which was diluted 400:1 in cyclohexane. The variation in the specific fluorescence of the SRC-I recycle solvent, wash solvent, and light oil (Table 1) parallels preliminary determination of their 1,2-benzpyrene (BP) content.[7] This is noteworthy because consideration is being given to the use of BP as the proxy compound for PNA determination in coal and oil-shale derived liquids.[8]

Milligram-level films of Oak Ridge National Laboratory (ORNL) hydrocarbonization oil and COED syncrude on both floor tile and metallic surfaces have also been examined in a less quantitative fashion. The film fluorescence was at least ten times stronger than the substrate fluorescence, which made the "spots" readily distinguishable.

Coal liquefaction products may contain certain organic compounds, heavy-metal inorganic materials, and particulate matter, all of which quench the fluorescence of PNAs and thus interfere with fluorometric monitoring techniques. Two such classes of aromatic compounds abundant in coal conversion products are simple phenols and acridines. We have tested for phenolic interference by adding large excesses of phenol to solutions containing perylene. Phenol did not interfere with our fluorometric PNA determination. However, heteroatom aromatic compounds such as acridines, which are abundant in oils having a high asphaltene content and whose absorption maxima overlap the emission maxima for PNAs, may partially quench PNA fluorescence. This quenching may explain the decreased sensitivity of the spotter to ORNL hydrocarbonization oil and to SRC-I light organic liquid (Table 1). Both materials undergo a large increase in specific fluorescence when dissolved in cyclohexane.

The spotter is capable of discriminating between classes of organic contaminants, such as PNAs and acridine dyes, by selecting optimal excitation and emission wavelengths with optical filters. The spotter can also discriminate the fluorescence of inorganic materials such as uranyl nitrate from the fluorescence of organic compounds due to the long luminescence lifetime of uranyl nitrate, although both materials have similar optical properties. The delayed fluorescence of uranyl nitrate results in a phase shift in its fluorescence signal relative to the fluorescence signal from organic compounds. Thus the relative amplitudes of the two phase-component output voltages from the phase-sensitive demodulator will be different for the two types of fluorescent material. The spotter is sensitive to 1-mg quantities of uranyl nitrate and could conceivably be used to locate spills or leakage in the nuclear fuel and waste-handling facilities. This phase-shift measurement capability of the spotter may also be useful in differentiating PNA fluorescence from the background luminescence of inorganic pigments commonly used in paints.

The spotter will be particularly useful in quantitatively measuring PNA skin contamination caused by contact with coal-derived liquids. The currently used technique in at least one coal liquefaction facility is to periodically scan workers with a short- or longwave blacklight in a darkened room and to visually estimate the extent of contamination.[5] The uv beam of the spotter, which has an intensity of only 0.93 mW/cm^2, is three to six times less intense than sunlight in the 350- to 400-nm wavelength band;[6] therefore, exposure of contaminated skin to the spotter beam does not pose an unusual health hazard with respect to possible cocarcinogenic effects involving uv light and PNAs. Accurate measurement of skin contamination will enable the effectiveness of various coal plant health protection practices (e.g., protective clothing, barrier creams, and various methods of cleaning contaminated skin) to be evaluated. It will also provide accurate data for correlation with the incidence of skin lesions.

FUTURE DEVELOPMENTS

An extensive field testing program for the fluorescence spotter will begin during FY 1980 to assess the usefulness of the spotter to fossil energy conversion plant health protection programs. Two advanced-version spotters, which can operate either from ac power or from batteries, are currently being fabricated at ORNL. Planning is underway for onsite testing at the PAMCO SRC pilot plant at Ft. Lewis, Washington, the Pittsburgh and Morgantown Energy Technology Centers, and the Hygas Coal Gasification Pilot Plant in Chicago. Field testing program activities will include monitoring plant personnel for skin contamination. The data gathered in this program should be useful (1) for comparison with in-plant air monitoring PNA measurements, (2) for correlation with the incidence of skin or respiratory health problems, and (3) for the establishment of good housekeeping and health protecton practices in such facilities.

ACKNOWLEDGMENTS

The technical assistance of M. S. Blair, G. K. Schulze, and M. L. Bauer, of the ORNL Instrumentation and Controls Division, is most appreciated. Coal conversion and oil-shale-derived samples were obtained from the ORNL Analytical Chemistry Division repository. This research was sponsored by the Office of Health and Environmental Research and the Office of Fossil Energy, U.S. Department of Energy, under contract W-7405-eng-26 with the Union Carbide Corporation.

REFERENCES

1. Report of the Working Group on Assessing the Industrial Hygiene Monitoring Needs for the Coal Conversion and Oil Shale Industries, Otto White, Chairman, Brookhaven National Laboratory, August 1978.
2. D. D. Schuresko and G. Jones, "A Portable Fluorometric Monitor to Detect PNA Contamination of Work Area Surfaces," p. 213 in Proceedings of the Symposium on Assessing the Industrial Hygiene Monitoring Needs of the Coal Conversion and Oil Shale Industries, Brookhaven National Laboratory, November 1978.
3. D. D. Schuresko et al., unpublished results.
4. D. W. Nebert and H. V. Gelboin, J. Biol. Chem. 243(23), 6242 (1968).
5. J. Smith, private communication, July 1979.
6. S. L. Valley, p. 16-2 in Handbook of Geophysics and Space Environments, McGraw-Hill, New York, 1965.
7. H. Kubota et al., private communication, July 15, 1979.
8. R. B. Gammage in Proceedings of the Symposium on Assessing the Industrial Hygiene Monitoring Needs of the Coal Conversion and Oil Shale Industries, Brookhaven National Laboratory, November 1978.

The Legislator's Viewpoint on Fossil Energy Conversion

Ms. Patricia Schroeder, U. S. Representative, Colorado

Economists, scientists, businessmen and politicians are struggling to outline and define what the "energy crisis" really is and what we as a society can do to solve it. We have all listened to the grim analysis and bleak predictions our country will soon face if we do not meet the crisis head-on.

It is worth reviewing the last three decades to attempt to understand how the energy crisis crept up on the American public: how in 1948 the fact that the United States had become a net importer of oil went almost unnoticed; how the formation of OPEC in September, 1960 was not reported in the newspapers until two weeks after it had happened; and how oil price increases have been triggered by political incidents abroad, from Suez in 1958 to Iran in 1979. (Who could have predicted that an elderly cleric living in a suburb of Paris, communicating by cassettes with his followers, could have brought Iranian oil production to a halt?)

But we shouldn't become bogged down in analyzing how we neglected to cope with the problem in the past. We must also resist the temptation to search for villains --- whether they are Middle Eastern sheiks, oil company executives, environmentalists and government bureaucrats, or short-sighted politicians. Pointing the finger only serves to paralyze us and prevent proper action.

We have already witnessed how long gasoline lines have nurtured a growing divisiveness, pitting citizen against citizen in an age of energy scarcity. The interests of the oil and gas producing states of the Sunbelt are at odds with the needs of the energy consuming states of the Snowbelt.

Our goal is to reduce U. S. dependence on imported oil, making the transition with minimum shock to the economy, the environment and the American social structure. Public policy-makers must grapple with one essential, recurring problem that must be re-evaluated every step of the way: what role should the government take in stimulating the private sector into producing alternative energy sources and at what point should the government withdraw and let the market forces take hold?

In today's energy crisis, with new buzz-words such as "synfuels" and "cogeneration," it is easy for public officials to recount the glowing memories of the great collaborations between government and private industry, such as the Manhattan and Apollo projects. But we can't fool ourselves into assuming that the present crisis can be solved with the same techniques by which we put a man on the moon. Today's crisis is of such scope and complexity that it is transforming the economy, threatening to destroy political consensus and undermining traditional life-styles.

On May 26, 1961, President Kennedy asked Congress to shoot for the moon and, within eight years, Neil Armstrong captured the imagination of the world when he made a "giant leap for mankind." But our effort to reach the moon differs from our effort to achieve energy independence in one crucial way: during the Apollo program the government acted as both the provider of the program and its sole customer. The government was both the salesman and the buyer of its own product.

In attempting to retool our energy industry to adjust to the shortage of oil, the government is tampering and modifying the marketplace. In coping with the energy crisis the government does not have the luxury of being its own customer, but must predict and adjust itself to the market forces of supply and demand. Whether or not the public policy-makers can effectively deal with the market forces will determine how well we can pull ourselves out of the present crisis.

Let us now turn to some of the proposals being tossed around on Capitol Hill. Because of the immense and complex nature of energy development, I will focus primarily on synthetic fuels and the varying options and problems involved in developing synfuels.

As any member of Congress can tell you, it is impossible to keep up with all the technological and scientific projects being launched in the energy field. If a dictionary came out containing all the new energy buzz-words, it would probably be a best-seller.

One of the most comprehensive energy proposals now being considered by Congress is the controversial Energy Security Corporation. If President Carter has his way and this plan is implemented, a handful of planners in Washington would be making decisions on how to channel up to $88 billion into new energy ventures over the next 12 years. The Energy Security Corporation would be chartered as a quasi-private corporation and would be exempt from restraints that most agencies must meet. Thus, it would not be directly accountable to either Congress or the White House. Not surprisingly, the President's proposal has already run into serious opposition. Again, the fundamental problem for public policy-makers is how to reach a goal --- in this case, developing a healthy synfuels industry without drastically affecting the private marketplace. Critics of this program argue that sapping such a huge sum of private investment money could pre-empt the credit markets, possibly crowding out more-needed investments.

Because synfuels are not yet economically competitive, some government participation will be necessary. It is apparent that the government must nurture a private-sector synfuels industry. However, the government's role should be minimized.

Rather than setting up the Energy Security Corporation as a separate entity, I think a better solution might be to shape up the Department of Energy, and give the responsibilities that would be given to the ESC to the Synthetic Fuels Division within that department. That way, you could avoid adding another layer of bureaucracy to an already over-burdened government and allow the Department of Energy to play a responsible role in carrying out our energy program.

President Carter has also called upon Congress to create a three-member Energy Mobilization Board that would have power to issue permits and otherwise speed construction of refineries and other energy projects if local, state or federal agencies acted too slowly. This new board would have sweeping powers to designate non-nuclear energy projects as "critical" to meeting the 1990 oil import goal and to establish binding schedules for governments at all levels. If any governmental entity, including state and local governments, failed to keep the schedule, the board would have the power to make the decisions itself.

The President has termed these powers as "cutting red tape." I'm all for doing away with needless bureaucratic footdragging and nit-picking regulations, but I would be opposed to "cutting red tape" if it becomes a euphemism for abrogating state perogatives in the development of our energy resources.

On June 26, the House passed the multibillion-dollar Synthetic Fuels Bill to create substitutes for oil and gas from coal, garbage and other materials. This bill calls for the producion of the equivalent of 2 million barrels a day in synthetic fuels. The federal government has already spent millions of dollars on the research and development of synthetic fuels. It is now building a partnership with private industry to demonstrate the commercial feasibility of various techniques, such as using chemical solvents to convert coal to a liquid. The multibillion dollar synfuels investment is the heart of the energy proposal now before Congress.

I have largely supported synfuels development. However there are many aspects of the synfuels issue that myself and other members of Congress have had to deal with in the wake of the President's proposed Energy Security Corporation and the $88 billion that will be spent on a "crash program" in synfuels development. Let me briefly discuss some of the considerations which have crossed my mind as I have grappled with both the hopes - and the false hopes - of synfuels development.

First of all, it should be kept in mind that no matter how rapidly synthetic fuels are developed, a barrel of synthetic crude does not necessarily supplant a barrel of oil on a one-for-one basis. Synthetic processes do produce liquid fuels, but the most promising are primarily targeted for use in utility and industrial boilers, not as replacements for gasoline and home heating oil.

Utilities burn about 10 percent of our daily oil consumption, and industry accounts for another 20 percent. Transportation, however, is by far the heaviest user at 54 percent of demand and is rising the fastest at about 4 percent per year. Residential and commercial uses account for 16 percent. So, it would be fair to say that synfuels will have limited applications and, with a few exceptions such as gasohol, will have little impact on our need for fuel to run our cars, planes, trains, and buses.

Going back to the use of synfuels in the utility and industrial sectors, it should be recognized that most of these users are already moving away from oil because of price pressures and the federal coal conversion program. As a result, synthetic fuels would not serve as a replacement for imported oil as much as they would substitute for coal. However, in parts of the country where coal cannot be burned because of the already-poor air quality, clean synfuels could be an alternative to the burning of oil.

Moreover to the extent that synthetics free up oil being used in the utility and industrial sectors, refineries could increase the percentage of their production devoted to gasoline, diesel fuel, home heating oil and other premium fuels. This may be an expensive but necessary way for synfuels to make a significant contribution to the supply of these critical fuels.

Secondly, just how much will a synthetic fuels industry grinding out 2 million or more barrels of product per day in 1990 cost the American economy? The answer is anybody's guess.

President Carter has put an $88 billion price tag on his promotion program, but that price reflects the availability of windfall profits tax revenues, not a thoughtful analysis of synfuels' cost. And the administration projection, as well as many others, tends to state only the cost to the government. It is much harder to assess how much private investment capital, in addition to government finances, would be required to meet the target.

Construction costs alone of 40 synthetic fuel plants producing 50,000 barrels per day would come in at a minimum of $80 billion, exclusive of operating costs, the cost to the economy of expensive new fuels, financing, and so on. In addition, there are the unforeseen costs of boomtown growth, environmental cleanups, project failures, increased coal production and its effect on coal prices, and a number of other factors.

Moreover, some of the synthetic fuels now on the drawing boards would require modifications in the boilers of industries and utilities that would be the market for the new fuels. New systems for transporting the products to their markets may be needed. No estimate of this cost has been given.

Finally, what happens to investment in other, more efficient and productive sectors of the economy if government and private investment focuses too heavily on synthetic fuels? How will inflation, by most accounts the nation's most serious problem, be worsened? Whatever the bottom line, it is apparent that $88 billion is only the tip of the iceberg.

A third consideration is the dilemma of technology choices. If we are to embark on a crash production schedule, we will have to start building synfuel plants now. That means that industry will be forced to rely on the kind of established "first generation" technologies with which it has some familiarity. Unfortunately, these plants would rely on less efficient, expensive processes and their products would have greater market problems than the newer "second generation" technologies now being tested.

Industry is unlikely to be attracted en masse to such expensive potential "white elephants" which might be obsolete or uncompetitive soon after they begin operation. But if the federal government forces construction, or builds them itself, the taxpayers will be stuck with them. This will keep the price of synthetic fuels to the consumer unnecessarily high and could dry up investment capital needed to construct second generation plants.

On the other hand, if the crash program turns to second generation technologies, such as solvent refined coal, H-coal, and others, it runs the risk of significantly increasing costs and prematurely forcing technologies that might not work. In addition, private investors are not likely to go deep into such a market unless they are guaranteed a higher than average return on their investment. As a result, it is likely that the taxpayers will end up assuming the large risks, and the government may end up running the plants.

Perhaps the best approach would be to build a small number of first generation plants, which would hopefully generate capital and provide some operating experience, while stepped-up work on second generation technologies is spurred on by sensible government incentives. This would seem to be the course most likely to keep costs and social environmental risks at a minimum, and get a substantial synfuels industry on its feet by early in the next century.

A fourth consideration - and one which will have a large impact on Colorado and the West - is siting. With a 10-year two million barrel-per-day goal, we would have to build 40 synthetic fuel plants with a 50,000 barrel-per-day capacity. Each plant is roughly equivalent to an oil refinery, and it is important to note that not a single major refinery has been sited and built in this country in the past 10 years. So, our perception of what this will entail may be more optimistic than the reality.

For example, the expectation that 40 synfuels plants could be constructed in the next 10 years is very optimistic. Even operating under "fast track" or energy mobilization board schemes, obstacles such as local opposition, clean air requirements, availability of adequate coal and shale reserves, and sufficient water for processing and cooling purposes will present serious obstacles.

Even the Department of Energy has recognized that siting considerations will probably be the most significant barrier to synfuels development. DOE could find only 40 counties in America that could support production of 100,000 barrels of coal-based synfuels per day. Three of these counties are in Colorado. On the other hand, 159 counties were found to have adequate coal reserves to supply these plants and could be potential locations if air quality requirements were eliminated or if the coal could be transported to a distant county without adequate resources.

This analysis gives a hint of just how difficult the siting problem might be and, above all, the potential for delay.

A problem closely related to siting is boomtown development. When a synthetic fuel plant is constructed, a lot more than coal and concrete moves into the town. People to construct and operate the plant, the mine and related facilities move in as well. DOE projects that a 100,000 barrel per day complex, including mining operations could involve 20,000 people. In Northwestern Colorado, where the bulk of the 400,000 barrel-a-day oil shale industry will occur, state officials have predicted the influx of up to 70,000 new residents.

The effect of such growth might be negligible if it were to happen in a major city. But 31 of the 41 counties identified as potential sites have populations of less than 50,000 and 26 of the 27 Western counties identified have populations of 1,000 to 20,000.

Rapid growth in sparsely populated areas, perhaps as much as a 20-fold jump in 10 years, does more than devastate rural charm. It means that recreation, schools, fire and police protection, transportation, hospital and health facilities, sewers, water and other municipal services must be provided.

DOE estimates that development costs would average about $7,000 per capita at 1979 costs. Thus, an oil shale plant with an associated population of approximately 6,600 people would generate more than $46 million in boomtown development costs, and a coal liquids facility with a top range of 20,000 new residents would have a boomtown price tag of more than $140 million. In Northwestern Colorado, with a population increase of 70,000, the boomtown costs would be around $490 million. In addition, making highway improvements required by oil shale and other energy development would cost Colorado another $385 million. This cost is likely to fall primarily on the shoulders of the federal taxpayer. Legislation to provide federal grants to help ease boomtown problems has been bouncing around Congress for several years, but nothing has been enacted which will meet the magnitude of the problem.

Another problem which I touched on before comes down to a matter of Federal-State relations. If 40 synthetic fuel plants are to be sited, constructed, and made operational in the next decade, a lot of decisions will have to be made in a hurry. The idea behind "fast track" and the energy mobilization board legislation is that decision-making schedules must be compressed and - in the minds of many - state, local, and federal laws waived.

These decisions will be made in Washington, probably by a relatively small group of people. Strains between regions of the country and the Federal government could be exacerbated if those regions begin to believe that national-interest energy projects are being shoved down their throats.

This is especially true here in the West, where there are increasing signs of alienation and resistance to Washington-bred decisions. Angry over water policy and other issues, people in the West are insisting more and more that they be intimately involved in decisions affecting their resources - as well they should. The potential impacts of an emergency synthetic fuels program on the West's water, coal, agriculture, and community development are so immense that it is hard to imagine that the West will blindly accept directives from Washington on such crucial concerns. Moreover, many of these issues are bound to end up in the courts, as there are serious Constitutional questions here that must be faced.

Another important consideration is the effect of synthetic fuels development on the environment. Unfortunately, many have begun to confuse "the environment" with "environmentalists," and its importance to the survival of us all has begun to lose its meaning in the endless bureaucratic jargon about "standards" and "constraints."

We must realize that the environment is a complex system that we do not fully understand, but upon which all life depends. When the air is dirty, the water foul and the land polluted, it is not just unsightly. It causes death and disease. It costs money even if it is not cleaned up. It robs food-producing lands and waters of their productivity. The environment does not need to be, and cannot be made, pristine. But it can suffer only so many insults.

Synthetic fuels offer a paradoxical situation with regard to environmental questions. Several synfuel technologies hold the promise of clean new energies that can replace polluting fuels in industrial and utility boilers. To do this, however, the pollutants must be removed at the plant where the coal or other resource is converted, rather than spreading pollutants all over the country by burning fossil fuels in hundreds of powerplants or industry boilers. The pollutants which are a part of synfuels development will be limited to a few sites. Pollutants concentrated in this manner are theoretically easier to control.

However, the rush to synfuels threatens to wipe out whatever environmental advantage the technologies might offer. A major concern of potential synfuel investors and developers is that they be protected from future environmental standards and that waivers be granted from existing clean air and other environmental laws. The synfuels stampede could also eliminate the important developmental stages needed to carefully assess and respond to the environmental burdens any particular synfuels process might pose.

All in all, a reasonable balance must be struck between environmental protection and energy development --- a balance which will promote our overall well-being, both now and in the future.

Another problem with which we are all to familiar is water. Water is used for cooling and as agents in the conversion process in virtually all synthetic fuel technologies. DOE figures indicate that each 50,000 barrel-per-day plant is expected to consume between 5 and 10 million gallons of water per day. In Colorado, it has been estimated that production of 400,000 barrels-per-day of oil from shale would require 64,000 acre-feet of water per year for the shale plants and their operations alone. This is nearly one-fourth the amount of water used by the Denver Water Board to supply Denver and its suburbs, over 40 percent of the state's population.

Several government studies have concluded that enough water is physically available, even here in the West. But physical availability is only part of the question.

As we all know, Western water is a complex and extremely sensitive subject. The water needed by the synfuels industry may not be legally available to it, and, if it is, may be subject to curtailment in times of drought. The pressure to otain water rights could result in a synfuels industry, operating under the banner of "national interest," buying up land and water rights from existing users. This problem is already of concern to many Westerners, who see agriculture threatened by projected development.

An answer to the water problem may be tapping the massive, underground aquifers. But the long-term environmental effects of such an undertaking are not well understood.

The general concerns which I have just outlined begin to hit homne when the primary synthetic fuel technologies are looked at. Let us first focus on the problems associated with coal development and the coal-based synfuel technologies, and then on the other two primary technologies, oil shale and biomass.

First of all, a crash synfuels program will put heavy reliance on coal-based synthetic fuel technologies. Although coal is our most abundant fossil fuel and its expanded use seems inevitable, the sudden and massive production increase that would be required raises many questions.

Most of the second generation coal liquefaction and gasification technologies now being tested will, at best, convert about one ton of coal into 2.5 to 3 barrels of petroleum-like products. This means that the production of 1.5 million barrels a day of coal liquids by 1990 would require a significant increase in coal production.

This increased coal production will come primarily from Western strip mines - some of which will be in Colorado. It has been estimated that 700 square miles of the West would have to be strip mined to meet the anticipated demand. However, the interior department is just now gearing up its federal leasing program to make more tracts available to industry, and it will be years before it becomes fully operational.

The new mines will have to meet the standards of the strip mine law. That law is currently in turmoil. Implementation is at least a year behind schedule. The states who will be responsible for running reclamation programs are fighting with the Federal Office of Surface Mining over many reclamation standards. And the implementaiton of state plans is a year or more off.

Coal transportation is also in turmoil. There have been questions over whether our railroads can handle the increased freight already anticipated because of other coal-promotional policies. Although most synfuel plants would be relatively close to the mines, there still would be transportation problems. Moreover railroad hauling prices have skyrocketed in recent years.

Reclamation standards, coal hauling rates, new transportation capabilities and sudden increases in demand could jack up the price of coal significantly over what it is today. In that case, not only would the operating costs and product prices of synthetic fuels rise above present predictions, but existing coal users and their consumers would be adversely affected.

Let us now turn to the coal gasification and liquefaction technologies.

Coal gasification is riddled with economic, environmental and regulatory problems which are all constraining development. Most of the old, "first generation" technologies produce low and medium-Btu gas and by-products. These proven processes produce fuels with a variety of utility and industrial applications, but are expensive - at least double the current cost of natural gas.

Low-Btu gas has very low heating value and can only be transported for very short distances. Moreover, the costs of designing, building and operating plants is uncertain.

Medium-Btu gas has much better market possibilities, because it has higher heating value and can be shipped about 100 miles. But it still faces significant environmental, cost and operating problems.

Existing high-Btu gas processes have not been demonstrated on a commercial scale, and new, "second generation" technologies are now being pursued. If successful, they woud produce a pipeline-quality gas that could replace many current natural gas uses, including residential space and hot water heating. To date, however, no proven demonstration plant for high-Btu gas has been constructed, and the earliest estimate is 1983.

Coal liquefaction technologies have been known for years and can be used to produce methanol, synthetic crude petroleum and gasoline. The fuels themselves are clean, but the processes are inefficient, expensive and often environmentally unsound. They produce an expensive product - estimated to exceed $30 per barrel - and are not considered to be promising on a large scale in the United States.

Second generation technologies hold more promise. These include solvent refined coal processes, H-coal, and Exxon Donor Solvent. None have been commercially proven. In general, thse newer technologies tend to produce products that are less clean, but more efficient and potentially less expensive than their first generation counterparts.

In short, "King Coal" has promise and potential, but the most commercially ready and potentially the cheapest synthetic fuel process is oil shale. Many significant environmental and technological problems remain, however, and the relatively small area in which shale rock is located -- in Northwestern Colorado and in Utah, combined with other constraining factors, could keep the ultimate contribution of shale relatively low.

Last but not least is biomass. Congressional interest has focused on the production of grain alcohol for use in a mixture of gasoline and alcohol, known as gasohol. There is a raging controversy,however, over the cost of alcohol fuels, as a gallon of straight alcohol now costs 50 to 100 percent more than gasoline.

Another form of biomass which Congress has given a nod of approval to is the conversion of solid waste into fuels. I cosponsored a bill providing funding for municipal waste conversion in the 95th Congress. The bill became law, and as a result of this legislation and some other measures, 7 direct-burning and 25 fuel-producing plants now operate in the United States.

Problems involved with biomass energy sources center around the lead and other toxic chemicals that are released into the air during burning of solid wastes and around the trade-offs between growing crops for food and growing them for fuel. These are considerations which will have to be carefully weighed as biomass' contribution to solving our energy dilemma increases.

In closing, let me touch on a few of the more important points which I have discussed. First, the government's role in energy development has been ineffective, misguided and counterproductive. That makes it all the more crucial for the Federal Government to now carefully evaluate the direction it will take and act decisively once a decision is made. Moreover, it has become apparent that only the Federal Government has the financial resources necessary to launch many badly-needed new programs. In developing a synfuels industry, there are both short and long-term projects that require an appropriate federal role.

However, it is important to note that the United States cannot count on any single solution to the energy crisis --- experts themselves can't agree on how risky a venture synfuel development is. A sound energy policy must include many elements to meet our goal of reducing U. S. dependence on imported oil.

Finally, it is crucial for all public policy makers to re-evaluate the government's role every step of the way, always keeping in mind that our ultimate goal in achieving energy independence is for the government to withdraw from the picture and allow the market forces to take hold.

The bare facts are that we must develop alternative sources of energy and that we must develop them as quickly as possible. It can be done, and more importantly, it must be done.

PROCESS CLINIC

The Process Clinic panel members were asked to list their instrumentation and process control measurement needs in order of priority.

Name	Organization, Process Type
E. J. Chelen	Westinghouse, Energy Systems Operations; Low Btu Gasification

I&C Measurement Needs

1. Communication
2. Temperature
3. Mass flow
4. Gas composition
5. Bed density

R. Forney	Colorado School of Mines; Coal Mining Process Control

I&C Measurement Needs

1. Long wall mining horizon control
2. Fault detection in advance of face

J. L. Gendler	Hydrocarbon Research, Inc.; Coal Liquefaction

I&C Measurement Needs

1. Report generation using computers

C. Houser	Phillips Petroleum Co.; High Btu Gasification

I&C Measurement Needs

1. Solids flow at 800°F, 1500 psi
2. Temperature measurement at 2500-3000°F under slagging conditions

J. D. Naylor	Pittsburgh & Midway Coal Mining Co.; Coal Liquefaction

I&C Measurement Needs

1. High temperature/high pressure slurry measurements
2. Coal/slurry concentration on-line
3. Viscometry and rheometry
4. Plugging detection

M. S. Nutkis	Exxon Research & Engineering Co.; Fluidized Bed Combustion

I&C Measurement Needs

1. Instantaneous particulate size in hot flue gas 1600-1650°F, 15-16 atm for pressurized FBC

M. H. Scott The University of Tennessee Space Institute; MHD

I&C Measurement Needs

MHD Generator:

1. Plasma temperature and temperature distribution
2. Elemental gas analysis
3. Conductivity measurement

Hot Seed Recovery Section:

1. Particulate size distribution and mass loading

G. Weth Department of Energy, Division of Fossil Fuel Utilization; Fluidized Bed Combustion

I&C Measurement Needs

1. Solid feed measurement
2. Sulfur content of feed
3. Bed level profile for pressurized FBC
4. On-line particulate size and distribution
5. Alkali in gas streams
6. In-bed O_2 probes

R. J. Wright Department of Energy, Pittsburgh Energy Technology Center; MHD

I&C Measurement Needs

Dr. Wright agreed with Dr. Scott and emphasized:

1. Real time measurements
2. In-situ better than sampling

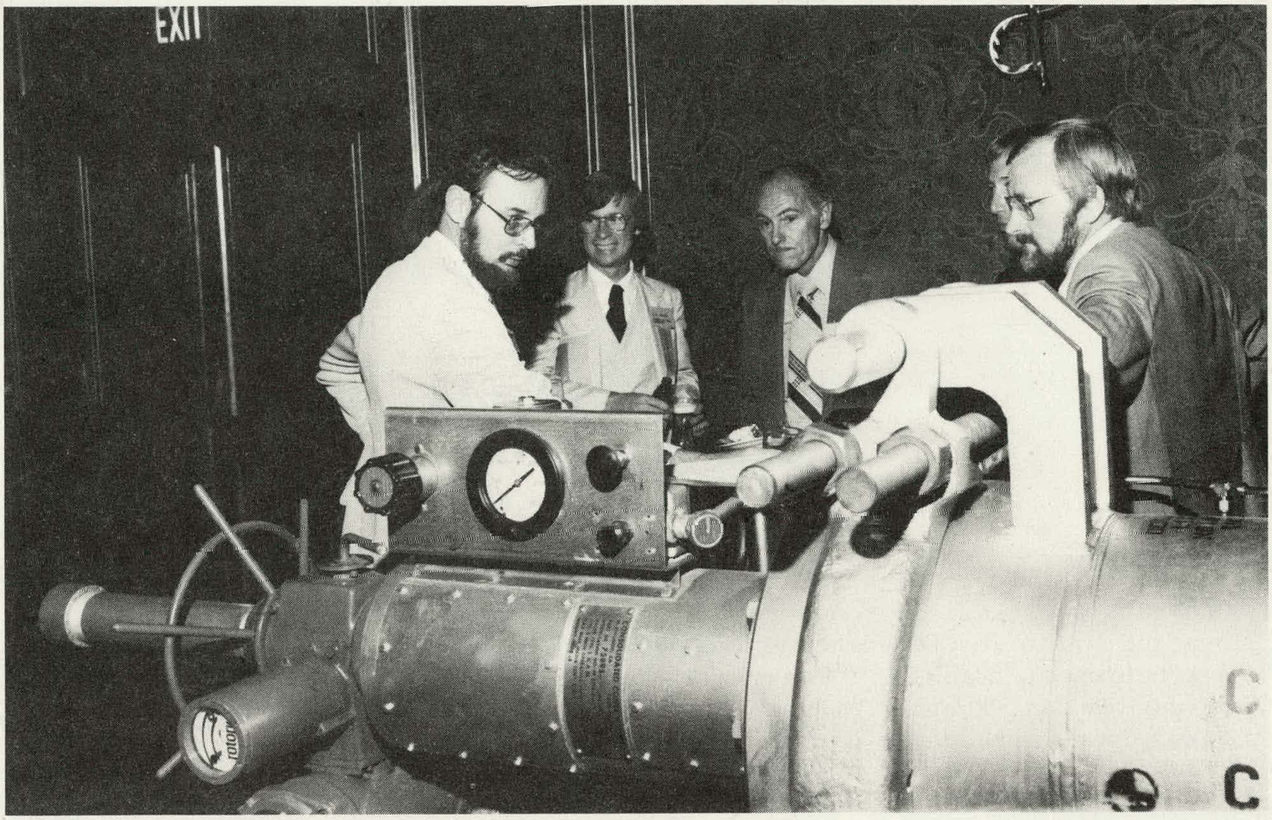
J. Yerushalmi Electric Power Research Institute; Coal Gasification

I&C Measurement Needs

1. Temperature measurement in high temperature, high pressure slagging gasifier
2. On-line analysis of coal feed
3. In-situ gas analysis


SPIRAL FLOW LETDOWN VALVE TRIM
FULL SCALE MODEL OF SPIRAL FLOW TRIM
FOR OIL LIQUEFACTION LETDOWN VALVE


METHODS OF THERMOCOUPLE CALIBRATION


EXIT
C
C

INSTRUMENTATION AND EXPERIMENTAL FINDINGS WITH A FLEXIBLE ROTOR SYSTEM

By
David W. Lewis, Professor
Ronald D. Flack, Assistant Professor
Edgar J. Gunter, Professor

Department of Mechanical and Aerospace Engineering
School of Engineering and Applied Science
University of Virginia
Charlottesville, Virginia 22901

1. ABSTRACT

A flexible rotor was instrumented and run with two sets of bearings. One set was an axial groove bearing and the second was a pressure dam bearing. The instrumentation included non-contacting proximitor probes with a synchronous tracking filter, and the signal subsequently was processed through a fast Fourier transform analyzer. The system response depends strongly on the design of the pressure dam bearings. The rotor does lock into a sub-synchronous whip during deceleration, after the system goes unstable. The particular instrumentation shows the kind of understanding that can come from a detailed analysis of a system in conjunction with appropriate instrumentation.

2. INTRODUCTION

This paper illustrates the kind of results that may be deduced from instrumenting a rotor system. The emphasis here is not on prescribing the type of instrumentation that should be used on a particular machine, but rather on the results from reducing the data obtained from even a simple rotor system employing a bare minimum of instrumentation. Common sense can provide a good starting point for the specification of the appropriate number and placement of accelerometers, velocimeters, or proximity displacement pickups and the type of monitoring that should be applied to a rotating machine. The proper logic, such that a machine is not accidently shut down, is also the type of information that common sense can provide. This work is a brief look at the processing of the signals that one might typically have available from a machine including the use of a synchronous tracking filter and a real time or FFT spectrum analyzer. This work is directed toward a relatively small rotating system in which two types of fluid film bearings were employed, both of which are rather common.

A typical instrumentation system available commercially is noted in Figure 1. Additional data reduction for analysis could be obtained by a fast Fourier transform instrument coupled to any of the measuring transducers. As noted in this system, axial measurements which might be used for an automatic emergency shut-down of the machine are dual measurements. Figure 2 exemplifies this concept in the measurement of the axial position of a shaft. Should one of the probes malfunction, the use of dual voting would not trip the machine off line. The machine operator would be made aware of the instrumentation problem so that it could be corrected.

Fluid film bearings are widely used because of the long life and the good damping characteristics that they do provide for rotating machinery. Considerable effort has been made to predict theoretically what should happen in a rotor system and these results show what experimentally does happen. The characteristics of a pressure dam bearing have been examined theoretically by Allaire, et. al. (1) for infinitely long bearings and by Nicholas and Allaire (2) for short bearings. Some experimental work has been done on this bearing by Leader et. al. (3). Several other authors have looked at the step bearing from a theoretical point of view (4-7). Both the circumferential location of the dam and the depth of the dam have been considered with the idea of optimizing these two parameters.

The Reference (2) shows that the dam depth ratio K', should have a value of approximately 3 for an optimum design, in which

$K' = (h_s + c)/c$

c = bearing radial clearance

h_s = step height

Some very good experimental papers have been made available especially through the works of Leader, et. al. (3) and Tonnesen and Lund (8). Most other experimental efforts have been limited to determining the bearing characteristics of rotors which are essentially rigid.

The Test Rotor

Figure 4 shows the schematic of the rotor which has a combined weight of the shaft and central masses of 13.6 Kg. The shaft diameter is constant (2.54 cm) which, when calculated, yields a first critical speed of 3300 RPM. This unit is driven by a one horsepower DC motor using a flat belt and flexible coupling. With the appropriate pulley ratio, the maximum speed of the motor of 2250 RPM can produce a rotor speed of 13,000 RPM.

The oil used in this particular test was the Shell Automotive type 10W-20W-50 heated to 54°C (130°F). The oil at this temperature has a dynamic viscosity which was measured to be 50 CP (0.75×10^{-5} lb-sec/in^2) with a viscometer. The dynamic viscosity was 195 and 35.5 CP at 30°C and 70°C, respectively. This particular rotor was fitted with a double thrust bearing at the outboard end which has a clearance of 1.27×10^{-2} cm (5 mils).

Both the axial groove and the step bearings were babbitt lined and without end seals. The length to the diameter ratio of the bearings is approximately unity.

Type of Instrumentation

The shaft motion is monitored by 8 non-contacting proximitor probes mounted at 4 positions along the shaft. The probes are mounted in pairs, oriented 90° one from the other in a circumferential direction, so that the actual shaft orbit shapes may be reproduced on an oscilloscope. The probe signal is connected to a proximitor which is an oscillator/de-modulator. The signal then goes to a synchronous tracking filter. The synchronous tracking filter may be selected to display either the total vibrational amplitude or the synchronous component of that motion. It also provides directly the speed through the sensing of the probe looking at the notch in the shaft as well as the phase angle, the angle between the maximum amplitude of vibration and the notch in the shaft.

For each bearing two test runs were made, the first of which was run at the maximum acceleration of the rotor system. This was run until the stability threshold was reached at which point the power was shut off and the rotor was permitted to coast to a stop. Typically, the average acceleration was 15 rad/sec^2. The second test was run with very low acceleration, again to the point where the stability threshold was reached. For the test, the motion and the speed were monitored using the synchronous tracking filter. All of the data was recorded on a 14 channel FM tape unit so that it could be further analyzed following the test.

The data was processed in several different ways. One manner was to plot the synchronous amplitude of motion at the various locations along the shaft as a function of rotor speed. Similarly, the phase of this synchronous motion was plotted versus the rotor speed. The second format was to plot the total amplitude that is, the synchronous plus the non-synchronous motion of the various locations along the shaft, as a function of rotor speed.

For the first test the transfer function of the system was found. This was obtained by taking the output from a proximitor probe used with the shaft notch and driving this into a dynamic sine wave converter to convert the once per revolution pulse into a constant amplitude sine wave with the frequency of the shaft speed. This sine wave was considered as representing a forcing function corresponding to the rotor unbalance. Using a fast Fourier transform digital signal analyzer with the output of one of the proximity probes and this sine wave just described, a transfer function was determined. The transfer function is the proximitor signal or output divided by the sine wave. This transfer function was plotted versus rotor speed and is compared to the output of the synchronous tracking filter.

From the second set of data, that is the data that was recorded with the slow acceleration, "cascade" or "waterfall" plots were constructed. A fast Fourier transform digital signal analyzer again was used to obtain frequency spectrums during the slow accelerations. One data sample was collected and analyzed in speed increments typically of 500 RPM. By plotting the spectrums vertically, the waterfall plots were obtained. It was found that with the low acceleration rate (2 rad/sec^2) one sample of each speed produced spectrums that were identical to those obtained at constant speed plateaus using 200 to 400 samples. This instrumentation is shown in Figure 5.

During the tests, several resonances were observed in the signals coming from the proximitor probes. These were subsequently determined to be structural resonances which are substantiated from impact tests. The velocity transducer was monitored at various locations of the structure for the different impact tests, and the output of the transducer was analyzed again with the FFT analyzer. For these tests, auto power spectrums (with peakhold) were used.

3. EXPERIMENTAL SUMMARY

Much information was obtained from this experimental work. Some typical results are presented here, as representative of the kinds of data that can be extracted through this type of instrumentation.

Axial Groove Bearing

These bearings maybe thought of as plain cylindrical journal bearings that are modified by having grooves cut into the horizontal split plane. These grooves provide access for admitting lubricant into the bearings. The test rotor was balanced using the axial groove bearings and cancelling the residual bow at the first critical rotor speed. From Figure 6 one can see the residual bow as exemplified by the slow speed portion of the curve. This figure shows in the upper left hand corner the location of the probe, in this case measuring the vertical displacement of the shaft near the left bearing. The main portion of this graph displays both the synchronous response as well as the total response at this particular probe location during the rotor run-up or acceleration. Note that the synchronous response dropped essentially to zero at the first critical speed of 3,250 RPM, indicating that the balance is removing the initial bow at the shaft.

As the speed is increased, a stability threshold is reached at 6600 RPM or approximately twice the first critical speed. Note that this threshold speed is presented graphically on the total response curve; however, the amplitude of the synchronous component is seen to be essentially constant at this same point.

The synchronous phase angle is seen to shift by 360° at the critical speed as shown in the upper portion of Figure 6. For a simple system a 180° shift at resonance is to be expected, but in this case the behavior is due to the initial shaft bow.

As previously noted, a more complete picture of the dynamic response of the system can be shown by a series of plots known as a cascade or waterfall diagram. This is shown in Figure 7, in which one can see the very large synchronous excitation response at 3100 RPM. However, at the instability speed of 6600 RPM a very large sub-synchronous component is produced at the 3100 CPM frequency. On this same plot, one can see frequency components that are two and three times the running speed. Note that at 1650 RPM a relatively large component is seen at 3300 CPM which is approximately the first critical rotor speed. This same information is presented on Figure 6 (total motion) showing quite distinctly the peak at 1600 CPM. The data presented here was for the case of rotor run-up; however for rundown the results were almost identical and hence are not presented. Such was not the case, however for the pressure dam bearings.

Pressure Dam Bearings

The rotor was run with five different sets of pressure dam bearings. The results of one set are presented here, set #1, which had K' values for the two bearings of 2.1 and 2.4. Figure 8 shows the synchronous motion as well as the total motion for the rotor during run-up. Thus, it can be seen that the critical speed stayed essentially the same as for the axial groove bearings. The system displays some resonance responses at 1600 RPM, 3300 RPM, and 4600 RPM and also a synchronous response at 9400 RPM. This system was accelerated up to the maximum speed that the motor was capable of reaching, specifically 13,500 RPM and did not reach the stability limit of the system. The synchronous phase angle displayed in the upper part of Figure 8 shows a change at the critical speed, but again not the 180 degree shift as might be anticipated.

The data presented in Figure 8 are for the probe located near the rotating mass at the center of the shaft and measured in the horizontal direction. As before, the FFT analyzer was used to deduce a transfer function for this case. The transfer function was described previously and will not be restated here. The relative data produced using this transfer function concept is summarized as Figure 9. This plot very closely represents the synchronous tracking filter plot of Figure 8. As can be seen, once again three synchronous resonances are seen: 3300 RPM, 4600 RPM, and 9500 RPM. The synchronous phase shifts are essentially the same as those observed with the synchronous tracking filter (although inverted due to the different definitions of phase angle of the two different manufacturers of the synchronous tracking filter and the FFT analyzer).

A revealing format for the presentation of data is that shown as a Nyquist form of the transfer function presented in Figure 10. The vectors representing the initial bow, δ_r, and unbalancing eccentricity, e_u are included. With this figure one can easily see why the classical 180° phase shift was not observed at the first critical speed. Here, clearly the center of the Nyquist plot was located outside of the Nyquist loop representing the first critical speed, due to the initial bow vector. Had the center fallen on the loop ($\delta_r = 0$) or inside the loop, 180° or 360° phase shifts would have been observed. The latter case was seen for the shaft with the axial groove bearings, as presented in Figure 6.

Two smaller loops are seen in Figure 10. These occur at approximately 4600 RPM and 9500 RPM and represent two structural responses of the system. The waterfall diagram for the pressure dam set #1 is presented in Figure 11. On this plot only the synchronous and twice synchronous frequency components are readily noticable while a third order component can be barely discerned. No sub-synchronous components are evident. This rotor system, particularly at high rotational speed, is very stable since the sub-synchronous component at the rotor first critical speed is non-existent.

Data from pressure dam set #2 for the same horizontal motion is shown in Figure 12 for run-up and in Figure 13 for run-down. This data is similar to the axial groove and pressure dam set #1 data, since similar synchronous and total motion resonances are present at 3300 RPM and 4700 RPM and 1700 RPM, respectfully. During run-up, the rotor with these bearings reached a stability limit at 9300 RPM (Figure 12). On the waterfall plot (not presented here) this instability was seen to excite the first rotor critical speed. Upon deceleration (Figure 13) the motion of the rotor is seen to differ from that of the run-up. During run-down the rotor locks onto the sub-synchronous motion and continues a large amplitude motion until the speed decreases to 8100 RPM. At a speed lower than 8000 RPM the deceleration and acceleration responses are nearly identical.

Theory Versus Experiment

Using the theoretical method developed in reference (2) Nicholas predicted the instability threshold of axial groove and pressure dam bearings as presented here. The specifications for the pressure dam bearings are presented in Table 1. Overall results are noted in Table 2 in which the experimental and theoretical instability thresholds are summarized.

In general, the comparison between theory and experiment is excellent with the exception of pressure dam set #2. One of the bearings in this set was damaged upon installation and the side rails of the dam were scored. This reduced the effectivenss of the dam since the lubricant could leak out of the sides, thereby reducing the effective load of the step and changing the stabilizing characteristics.

The speed range over which the rotor locks into a whip condition is referred to as N_w and for the data just presented amounted to 1200 RPM. In Table 2 one can see that value of N_w increases with the instability threshold. At this point in time, not enough data has been obtained to determine or generalize this relationship for pressure dam bearings.

Summary

This work shows the results that can be obtained by proper instrumentation of a rotating system. In this case, some results have been presented using an axial groove bearing and pressure dam bearings. The synchronous tracking filter and a FFT analyzer were used to reduce the outputs from the shaft monitoring proximity probes and from a velocity transducer used for monitoring structural resonances. The experimental results do seem to agree very well with theoretical results especially regarding the optimum value K' of the pressure dam bearing. With the FFT a transfer function technique has been developed that produces results similar to that obtained from synchronous tracking. By plotting this transfer function in a Nyquist form the effects of rotor bow can be easily recognized. Several structural resonances were observed in this experimental work with the probably causes identified by using the synchronous tracking filter and a FFT transfer function and spectrum analysis.

Acknowledgements

The authors wish to thank Drs. J. C. Nicholas, L. E. Barrett, P. E. Allaire, and Mr. M. E. Leader for their inputs to this investigation. This research was sponsored by the Department of Energy under Contract EF-76-S-01-2479 and the Industrial Supported Program for the Dynamic Analysis of Turbomachinery at the University of Virginia. Appreciation to Susan Shriner for the typing of this manuscript.

4. REFERENCES

1. Allaire, P. E., Nicholas, J. C., and Barrett, L. E., "Analysis of Step Journal Bearings - Infinite Length, Inertial Effects," ASLE Preprint, No. 78-AM-3B-1.

2. Nicholas, J. C. and Allaire, P. E., "Analysis of Step Journal Bearings - Finite Length Stability," ASLE Preprint No. 78-LC-6B-2.

3. Leader, M. E., Flack, R. D., and Allaire, P. E., "Experimental Study of Three Journal Bearings with a Flexible Rotor," Accepted for publication in ASLE Transactions.

4. Wilcock, D. F. and Booser, E. R., Bearing Design and Application, McGraw-Hill, New York, 1957.

5. Pinkus, O. and Sternlicht, B., Theory of Hydrodynamic Lubrication, McGraw-Hill Book Company, New York, 1961.

6. Kettleborough, C. F., "An Approximate Analytical Solution for the Stepped Bearing," Journal of Applied Mechanics, Trans. ASME, Series E, Vol. 83, 1961, pp. 507-510.

7. Hamrock, B. J. and Anderson, W. J., "Rayleigh Step Journal Bearing, Part II - Incompressible Fluid," Journal of Lubrication Technology, Trans. ASME, Series F, Vol. 90, 1969, pp. 641-650.

8. Tonnesen, J. and Lund, J. W., "Some Experiments on Instability of Rotors Supported in Fluid Film Bearings," Journal of Mechanical Design, Trans. ASME, Vol. 100, No. 1, January 1978, pp. 147-155.

9. Nicholas, J. C., Gunter, E. J., and Allaire, P. E., "Effect of Residual Bow on Unbalance Response and Balancing of a Single Mass Flexible Rotor, Part 1: Unbalance Response," Journal of Engineering for Power, Trans. ASME, Vol. 98, No. 2, April 1976, pp. 171-181.

10. Tondl, A., Some Problems of Rotor Dynamics, Publishing House of the Czechoslovak Academy of Sciences, Praque, 1965.

TABLE 1 PRESSURE DAM BEARING SPECIFICATIONS

BEARING TYPE	BEARING NUMBER	INSTALLED RADIAL CLEARANCE c (mm)	STEP HEIGHT h_s (mm)	K´ RATIO $(h_s + c)/c$	STEP LOCATION (θ_s)	L/D RATIO	ROTOR UNBALANCE (gm-cm)
2 AXIAL GROOVE	1	0.046	N.A.	N.A.	N.A.	1.0	22
	2	0.051	N.A.	N.A.			
PRESSURE DAM SET #1	1	0.056	0.064	2.1	145°	1.0	22
	2	0.064	0.091	2.4			
PRESSURE DAM SET #2	1	0.064	0.112	2.8	140°	1.0	20
	2	0.064	0.104	2.6			
PRESSURE DAM SET #3	1	0.061	0.340	6.6	150°	1.0	23
	2	0.064	0.483	8.6			
PRESSURE DAM SET #4	1	0.061	0.140	3.3	90°	1.0	20
	2	0.061	0.069	2.1			
PRESSURE DAM SET #5	1	0.053	0.569	11.7	140°	1.0	20
	2	0.061	0.442	8.3			

TABLE 2 SUMMARY OF EXPERIMENTAL RESULTS FOR SHAFT WITH PRESSURE DAM BEARINGS

PRESSURE DAM BEARING SET NUMBER	K' RATIO	θ_s (DEGREES)	EXPERIMENTAL N_{us} (RPM)	THEORETICAL N_{us} (RPM)	SUBSYNCHRONOUS LOCK-IN N_w (RPM)
2-AXIAL GROOVE	N.A.	N.A.	6600	6000	0
5	11.7/8.3	140	7800	7800	900
4	3.3/2.1	90	8600	8100	1000
3	6.6/8.6	150	8900	8850	1150
2	2.8/2.6	140	9300	11500	1300
1	2.1/2.4	145	>13800	11100	-----

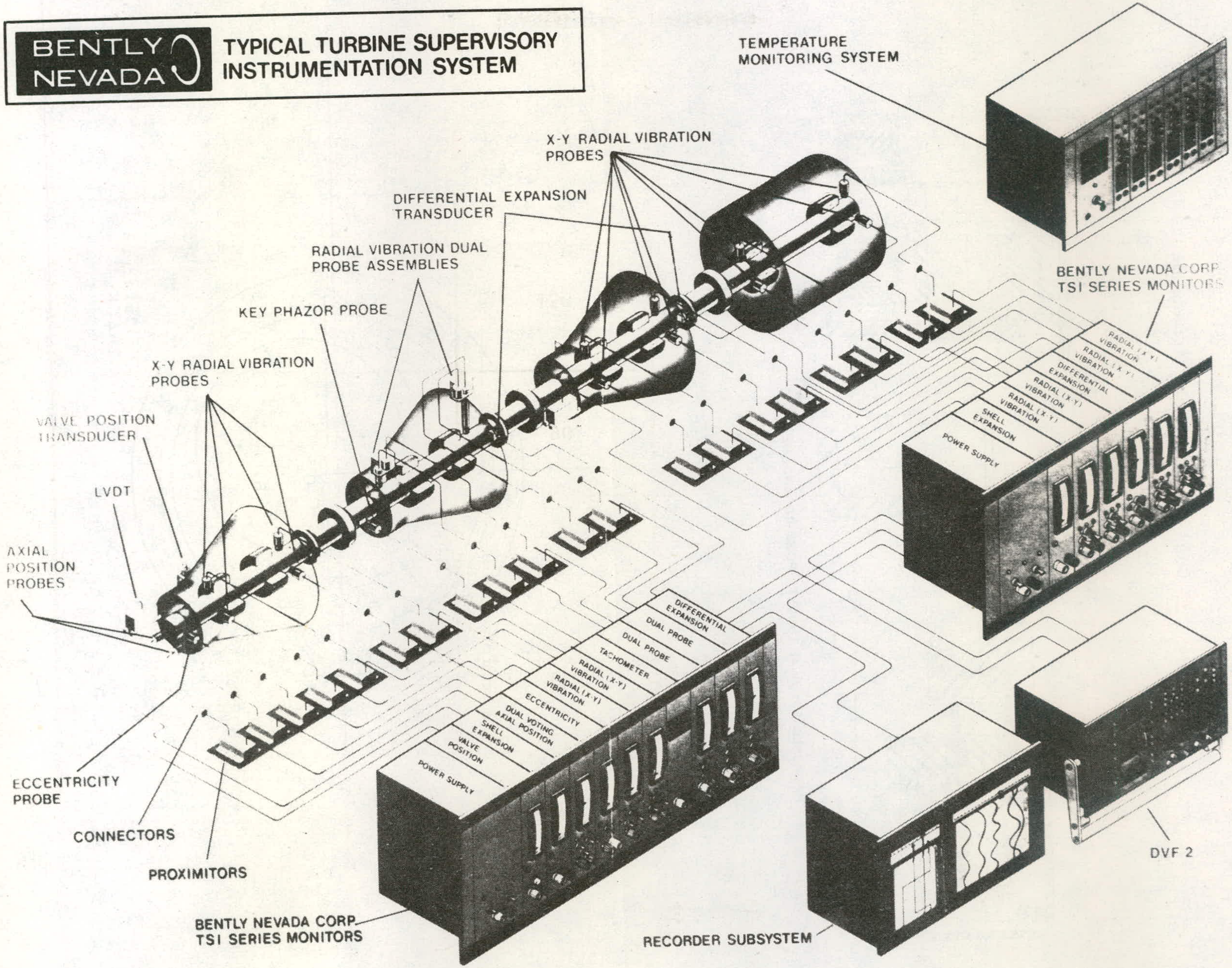
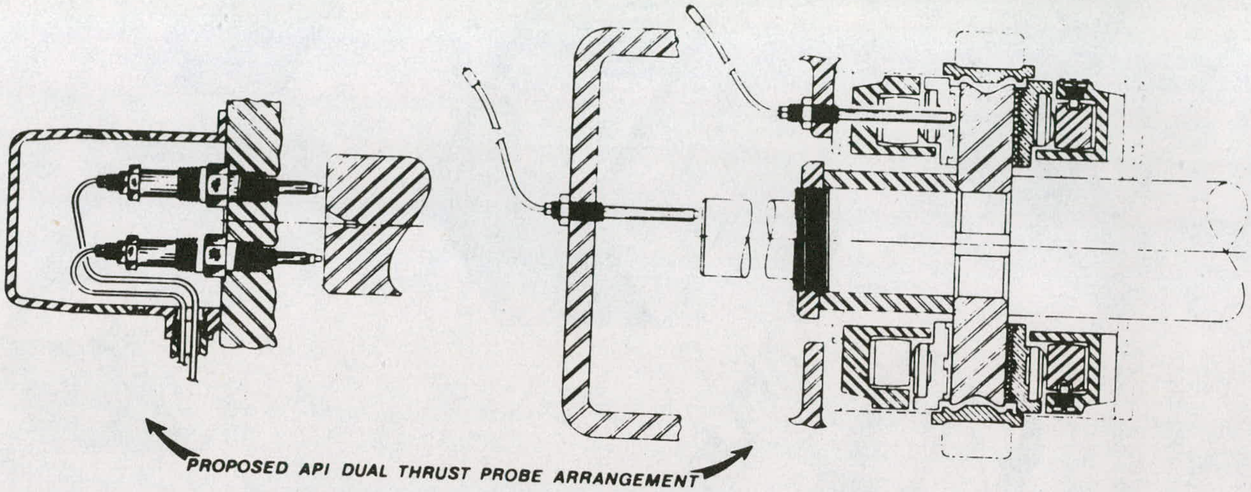
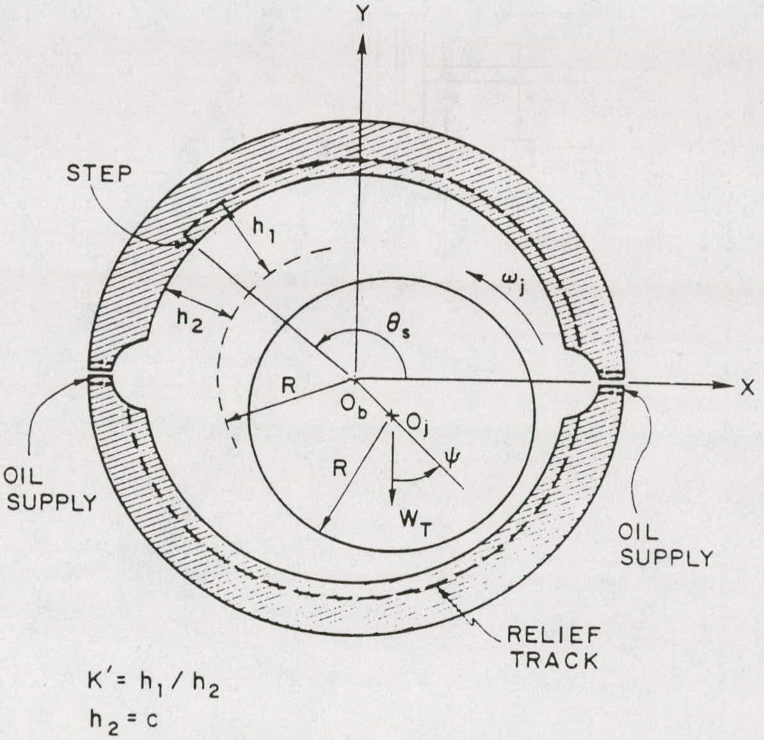


Figure 1 Supervisory Instrumentation System

Figure 2 Dual Thrust Probe Arrangements





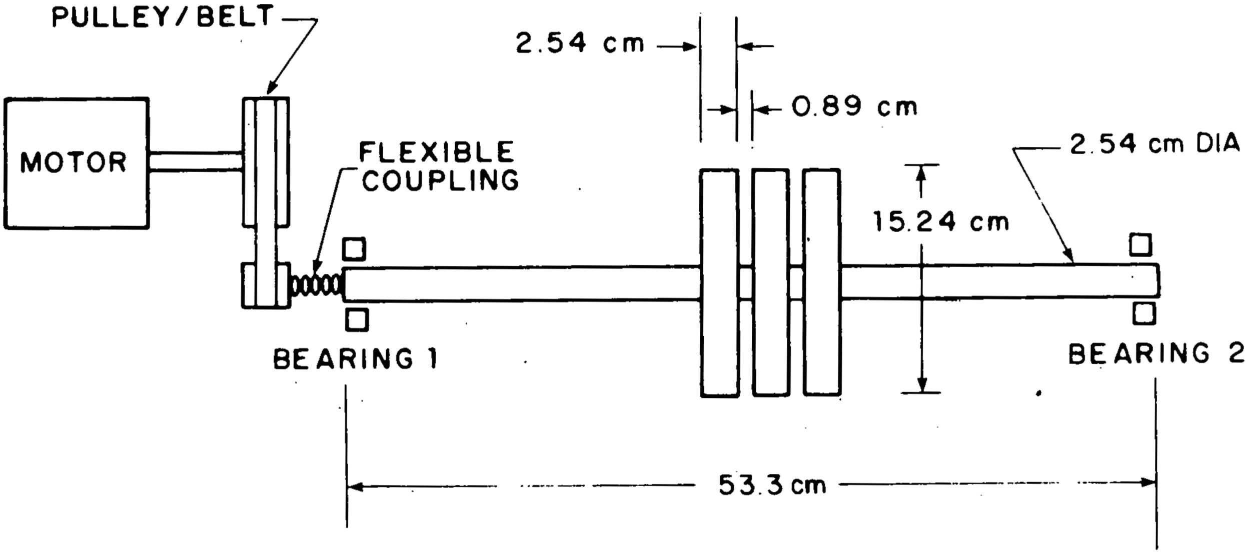
$$K' = h_1 / h_2$$

$$h_2 = c$$

$$h_1 = c + h_s$$

Figure 3 Pressure Dam Bearing Schematic

Figure 4 Rotor and Drive Assembly



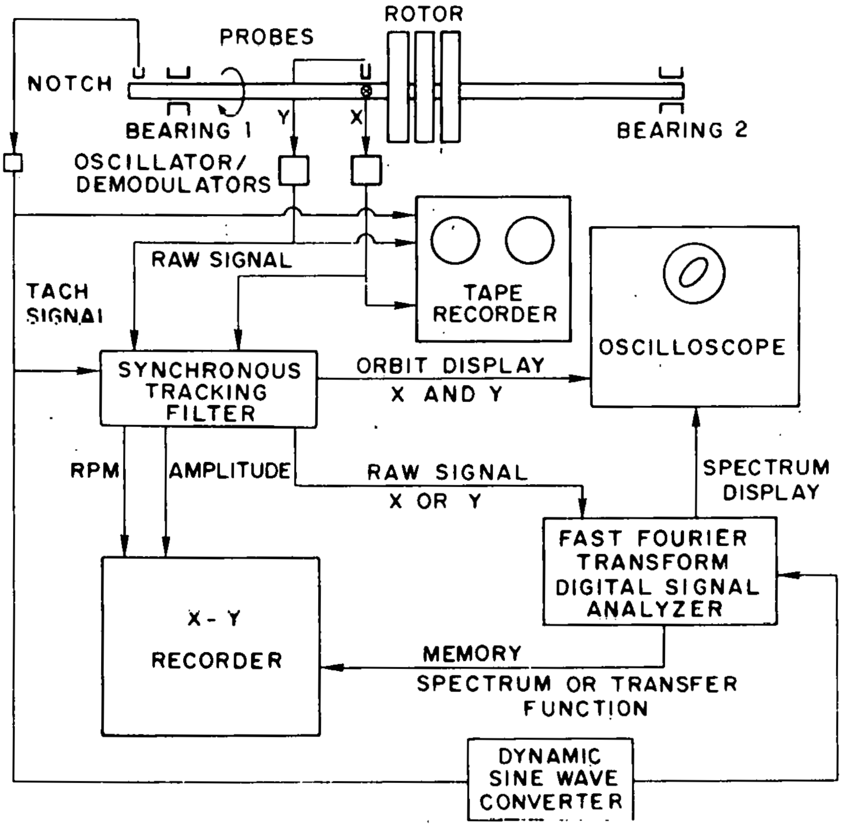
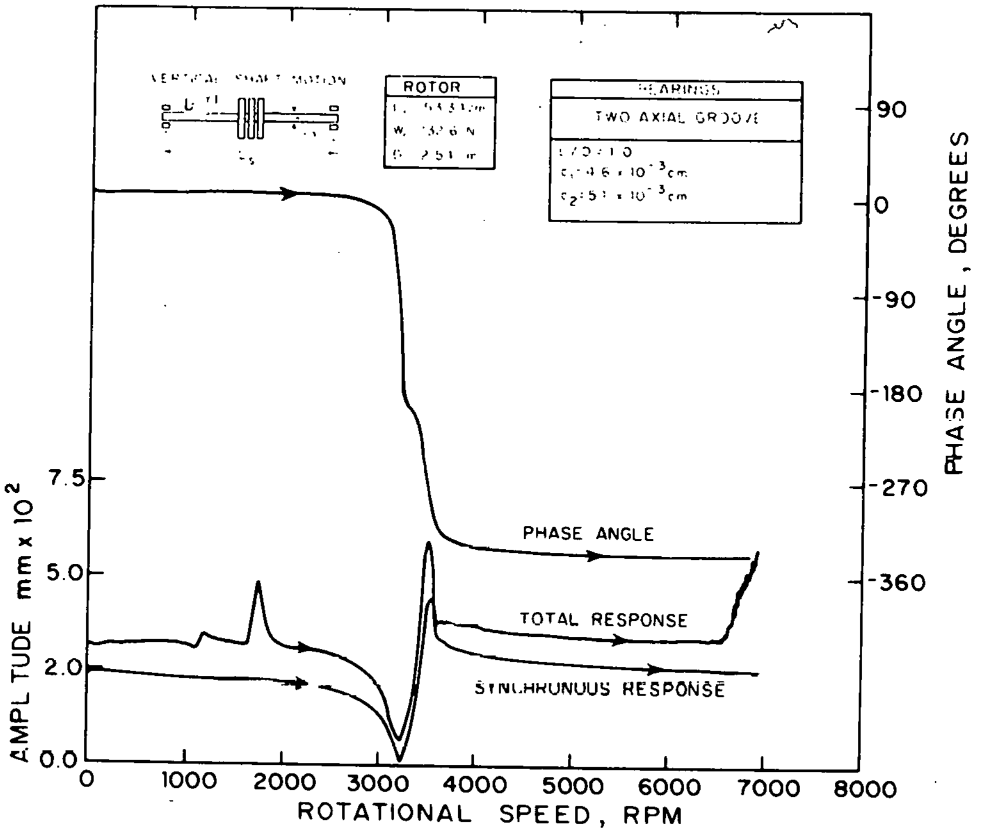


Figure 5 Block Diagram of Instrumentation

Figure 6 Y1 Synchronous and Total Motion, Axial Groove Bearings



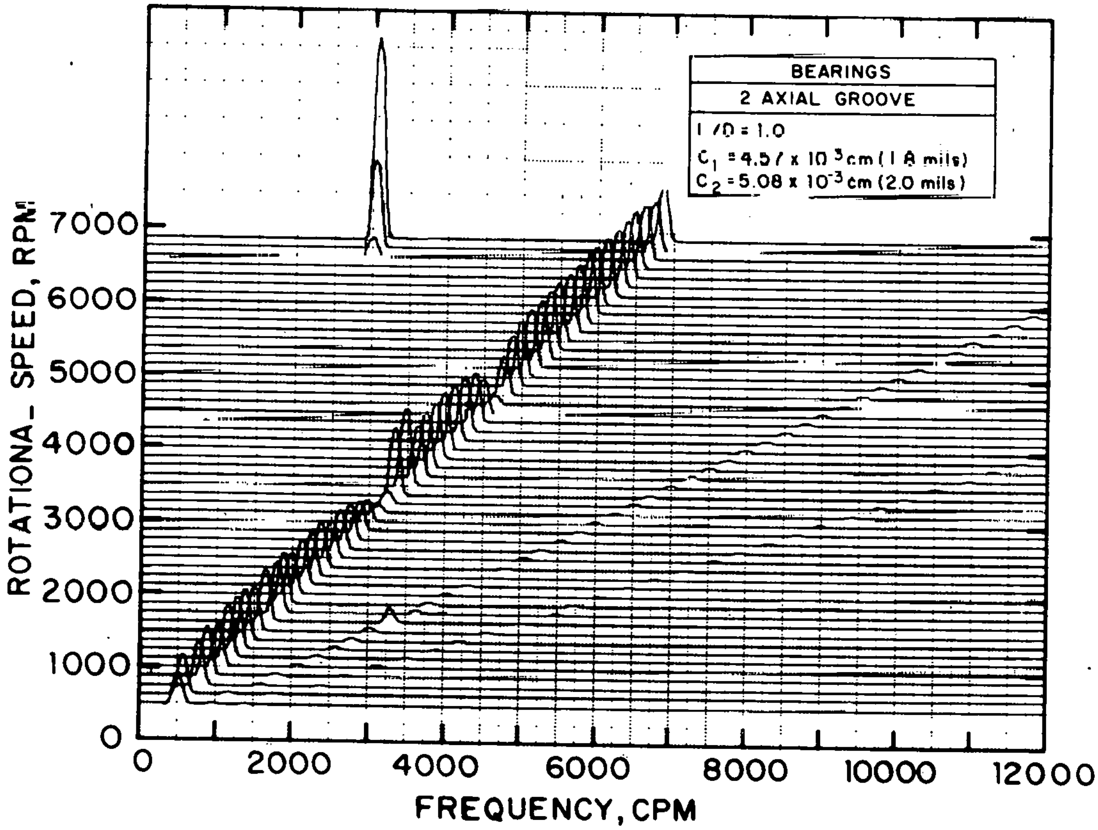
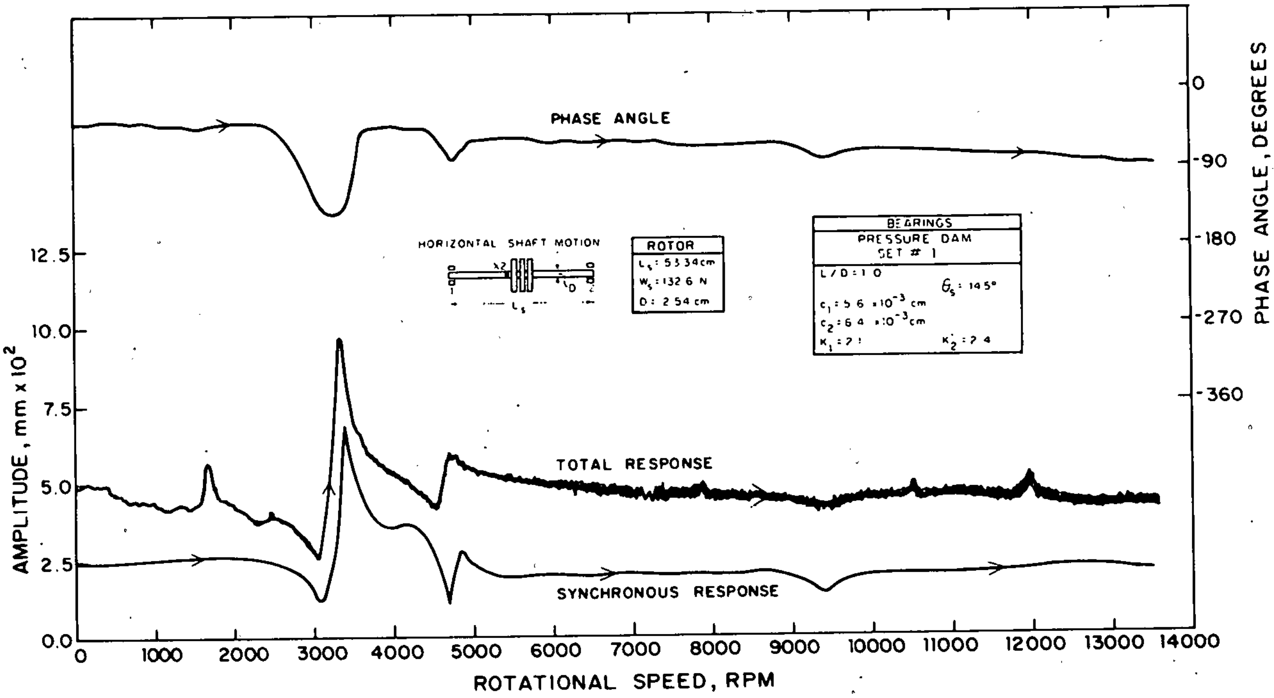


Figure 7 X2 Motion Cascade Plot, Axial Groove Bearings

Figure 8 X2 Synchronous and Total Motion, Pressure Dam Set #1



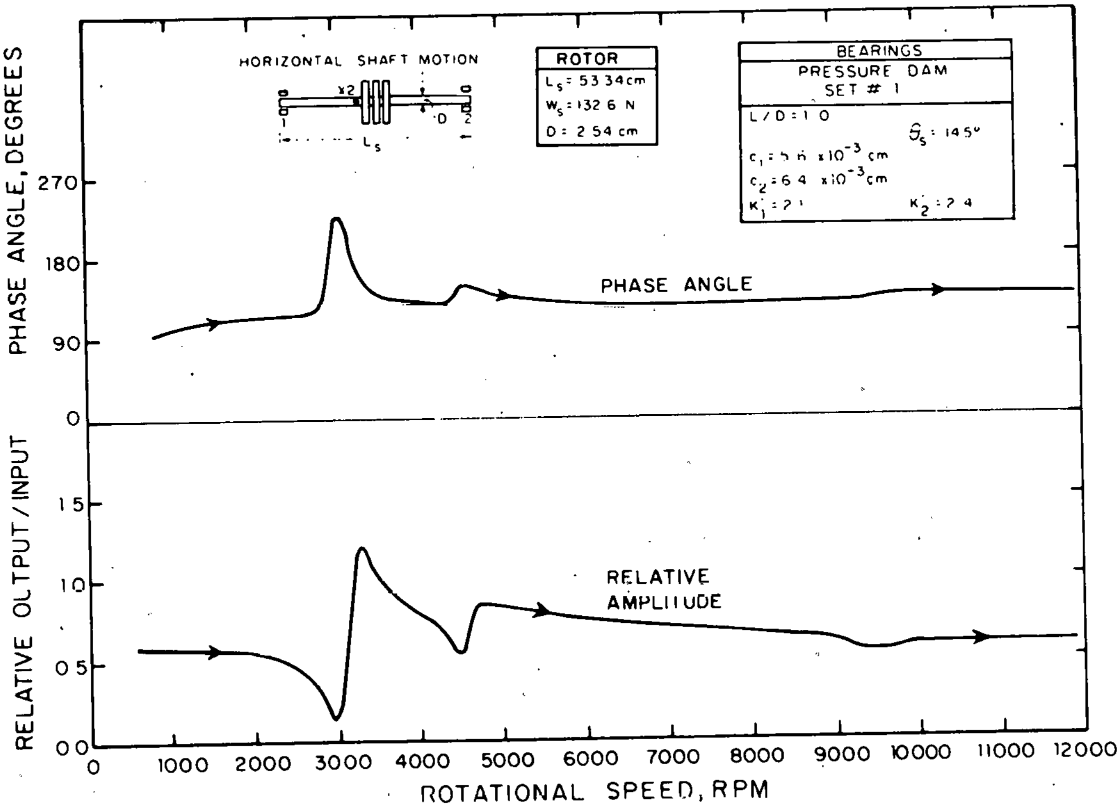
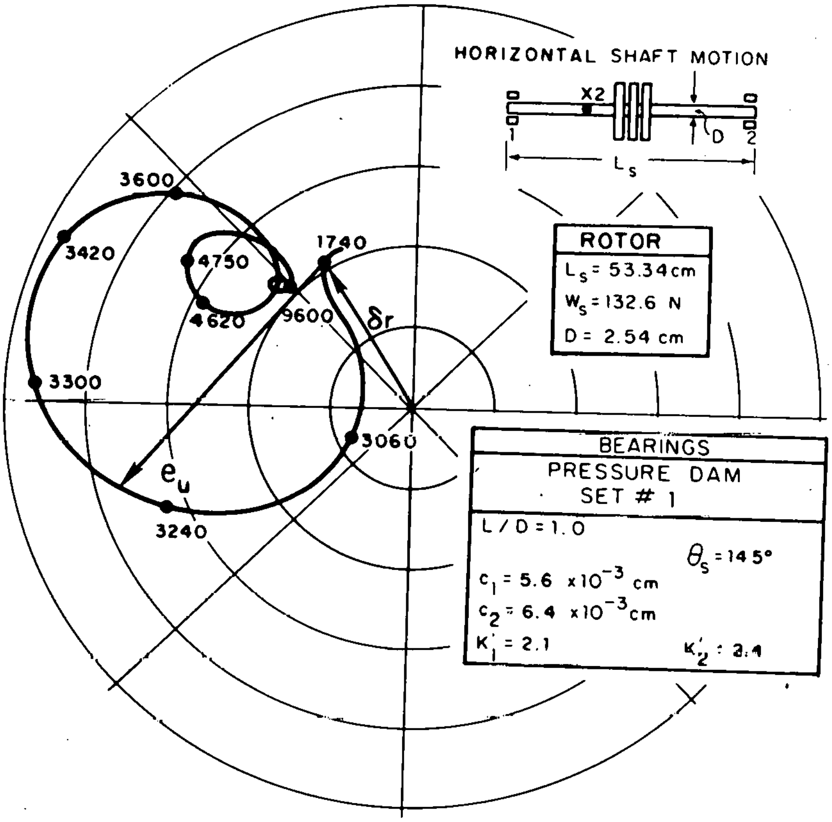


Figure 9 Transfer Function (X2 Motion = Output,
Rotor Unbalance = Input) Pressure Dam Set #1

Figure 10 Transfer Function - Nyquist Form (X2 Motion) Pressure Dam Set #1



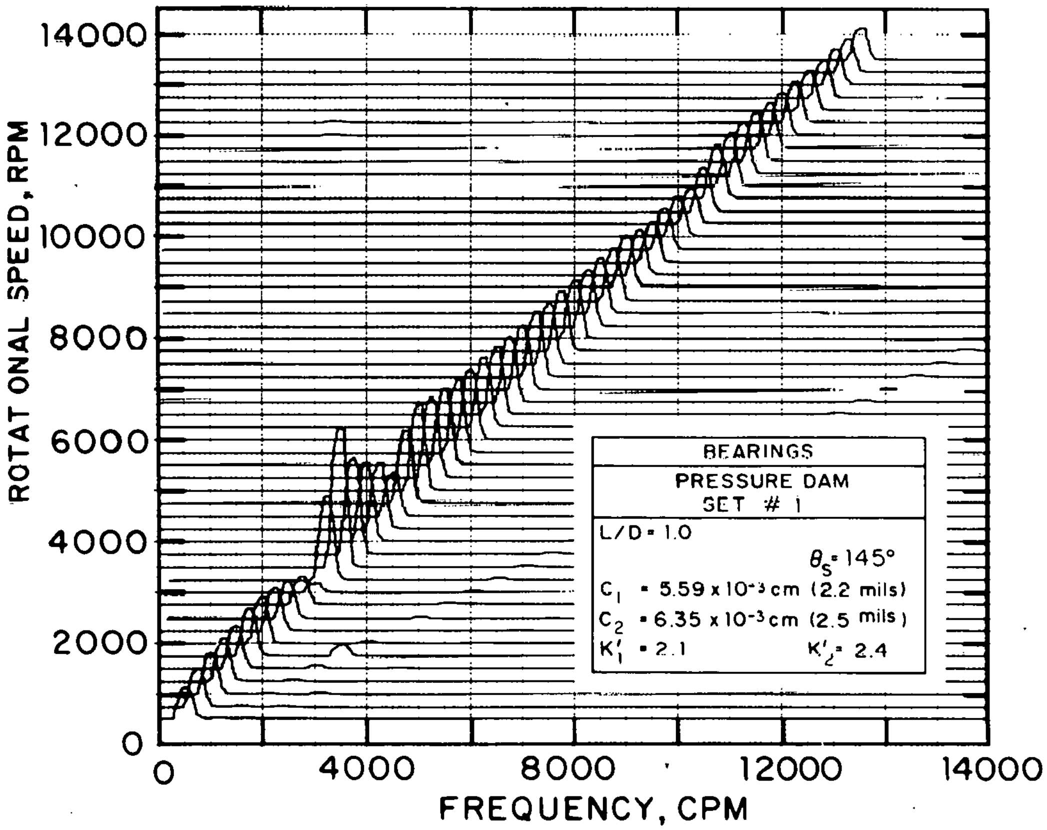
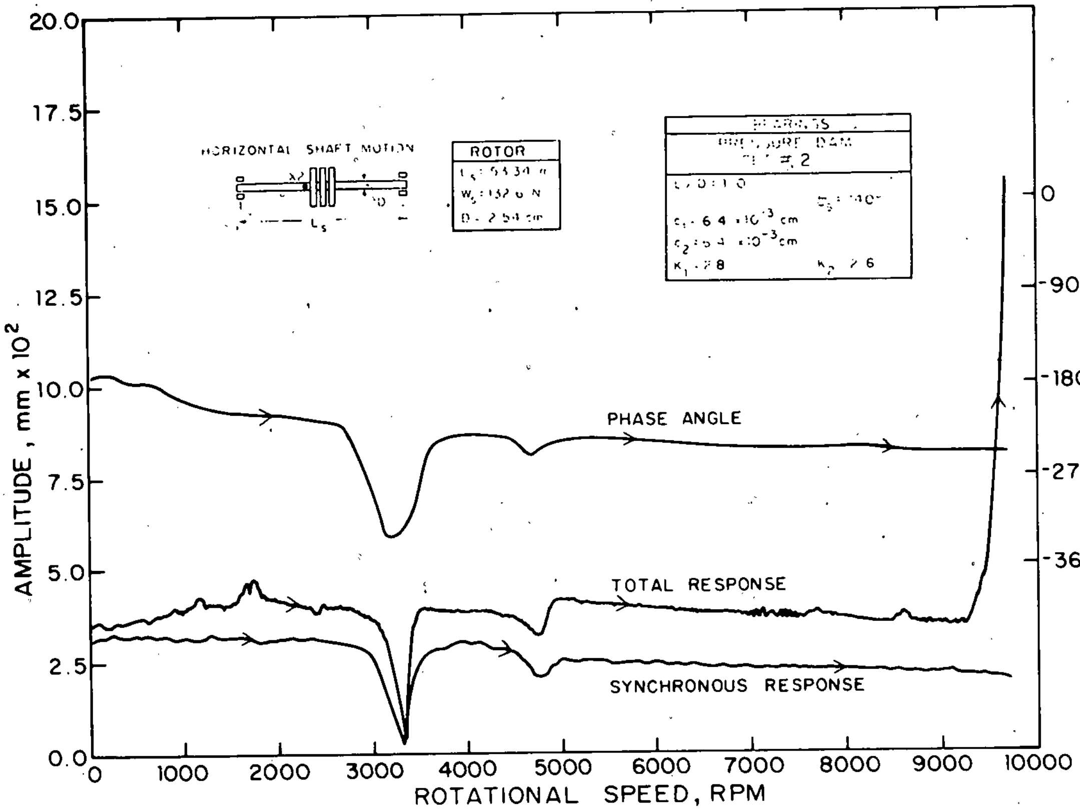


Figure 11 X2 Motion Cascade Plot, Pressure Dam Set #1

Figure 12 X2 Synchronous and Total Motion, Pressure Dam Set #2, Run-up



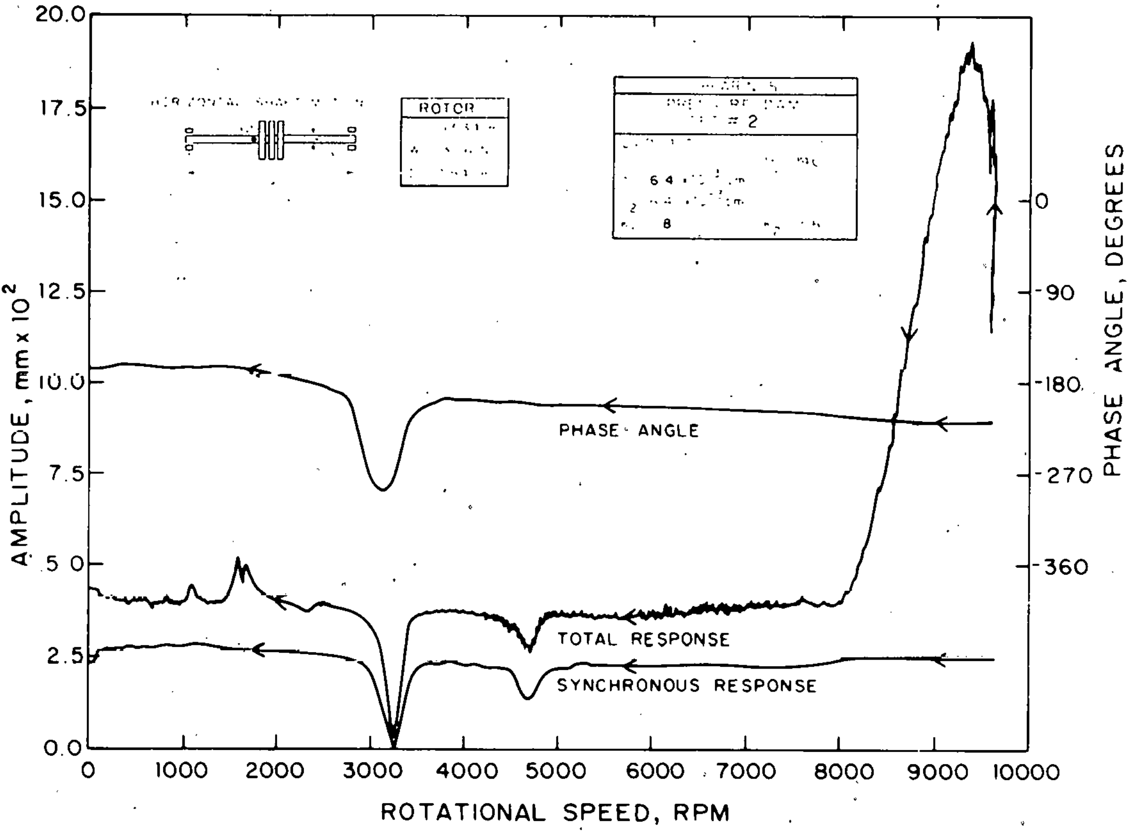


Figure 13 X2 Synchronous and Total Motion, Pressure Dam Set #2, Run-down

PROCESS CONTROL FOR ENVIRONMENTAL SYSTEMS: CASE STUDIES IN DESULFURIZATION

F. G. Mesich
D. G. Jones
Radian Corporation Pasadena

ABSTRACT

Sulfur species in gaseous effluents from fossil energy processes have long been recognized for potential adverse impact on the environment. Poor operating experience and/or failure of wet scrubbers in the early 1970's has produced growing recognition of the importance of chemical process control. Several case studies which describe desulfurization process control experience are presented. In general, desulfurization of process streams in large-scale coal gasification plants is less well understood and is not well documented compared with wet scrubbing systems used for coal-fired power plants. One of the major factors which has contributed to operating problems with wet scrubbers is inadequate reliability of critical process control sensors. The operation of conventional lime/limestone scrubbers is compared with some of the newer desulfurization processes such as dry scrubbing.

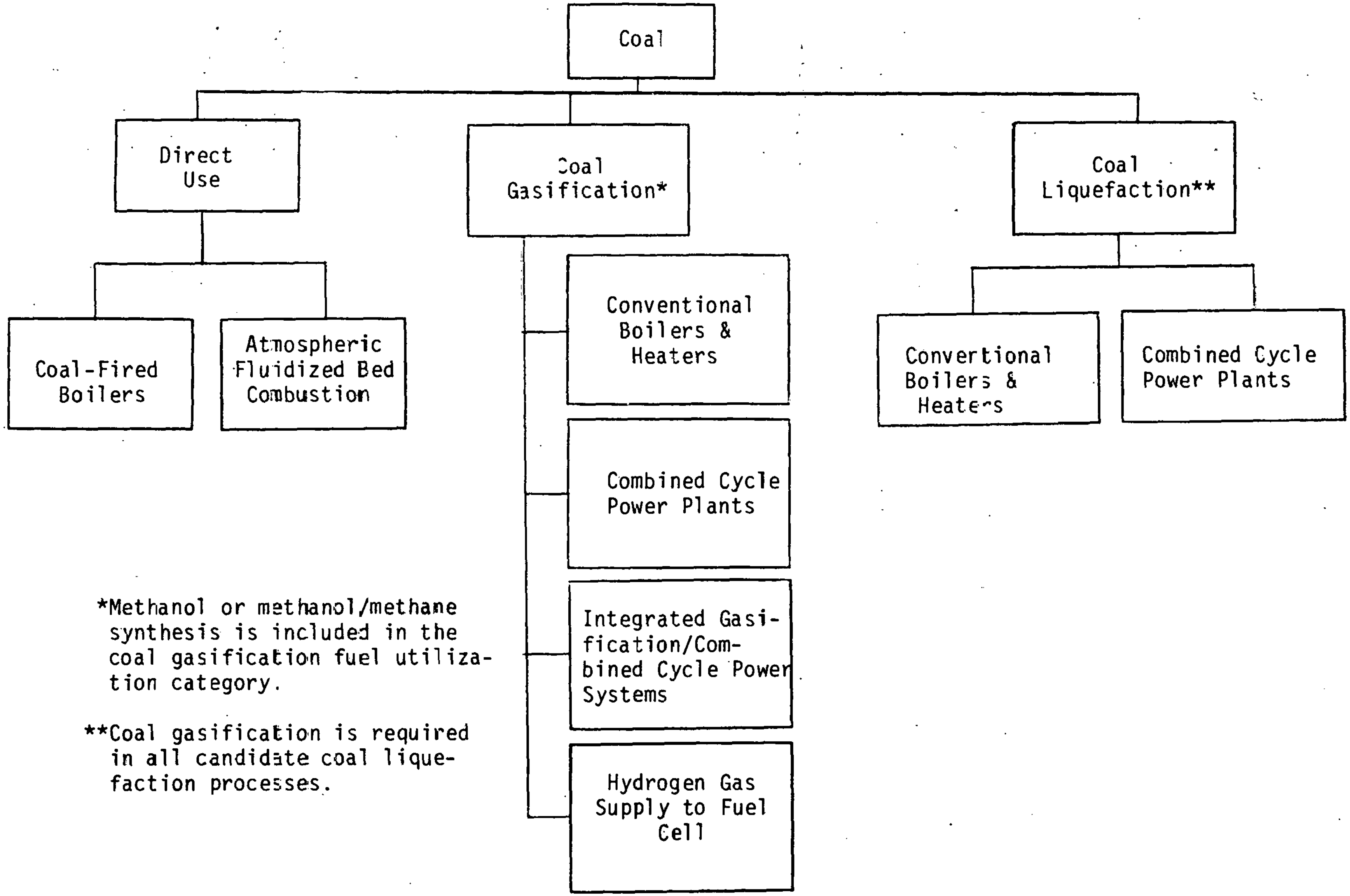
Dr. Mesich is an Assistant Vice-President of Radian Corporation and Dr. Jones is a Regional Manager of Radian Corporation. Radian's home office is located in Austin, Texas at 8500 Shoal Creek Blvd., with regional offices in Washington, D.C., Los Angeles, Salt Lake City, and Durham, NC.

1.0 INTRODUCTION

Coal utilization in the United States is currently oriented towards electric power production (*i.e.* over 200,000 MW) and processing industries such as steel manufacturing. Current regulations require flue gas desulfurization (FGD) for new coal-burning sources, and several new FGD technologies have emerged in the past few years. New priorities have also encouraged a more rapid pace of synthetic fuel technology development. As shown in Figure 1-1, large scale coal utilization for production of synthetic fuels requires pressurized coal gasification (Ref. 1).

There are only three large-scale, commercially-operating pressurized coal gasification plants in the world today. The largest of these is the Sasolburg oxygen-blown Lurgi plus Fischer-Tropsch liquefaction system, which was started up in the mid-1950's in an initial phase. The government of South Africa has moved ahead with phases two and three, which will result in the production of over 100,000 BPD of synthetic fuels in the early 1980's, using over one hundred Lurgi gasifiers (Ref. 1). The other two large scale coal gasification systems are the Kosovo Combine facility near Pristina, Yugoslavia and the STEAG gasification plus combined cycle plant in Lünen, West Germany. The Kosovo plant features six oxygen-blown Lurgi gasifiers and the STEAG plant utilizes five air-blown Lurgi gasifiers, which are then integrated with a 120 MW combined cycle power plant. Of these three facilities, the only published information regarding detailed sulfur removal data relates to the Kosovo experience.

Considering both environmental control requirements and current mandates for replacing industrial use of petroleum with synthetic fuels, it is probable that new processes must be developed and demonstrated to meet these needs. In spite of these anticipated changes, this paper identifies several case studies in desulfurization processes, based on current experience.



*Methanol or methanol/methane synthesis is included in the coal gasification fuel utilization category.

**Coal gasification is required in all candidate coal liquefaction processes.

Figure 1-1. Large-scale coal utilization alternatives.
Basis: near-term applications of advanced technologies.

2.0 CASE STUDIES OF DESULFURIZATION PROCESSES

Three case studies are presented and discussed. First, data obtained from the Kosovo coal gasification facility is presented. Then the process control features of full-scale lime and limestone wet scrubbers are identified. A third case study involving spray dryer plus baghouse systems concludes this section.

2.1 Kosovo Coal Gasification Facility

A process block flow diagram of the Kosovo Lurgi gasification facility is shown in Figure 2-1 (Ref. 2). The major process element of interest is the acid gas removal system (Rectisol), but sulfur species in gas-phase effluents from the lock hoppers, the tar separation vents and the phenol plant vents are also noteworthy. The estimated flowrates and measured compositions of these gas streams are provided in Table 2-1, which includes the following sulfur species:

hydrogen sulfide	(H_2S)
carbonyl sulfide	(COS)
methyl mercaptan	(CH_3SH)
ethyl mercaptan	(C_2H_5SH)

At Kosovo, the high pressure gas stream from the coal lock system is flared, while the low pressure gas stream is vented to atmosphere. In the United States, venting the low pressure lock hopper gas would not be an environmentally acceptable alternative. The location of these two gas streams with respect to the coal gasification processing system is indicated in Figure 2-2. Note the water scrubbers in Figure 2-2 which are used to separate tars, oils, and phenols from the raw product gas. These materials condense under a gasifier operating pressure of about 370 psia, and when the liquids are depressurized in the tar separation section, flash gases are generated in the separation vessels. Some of this gas is flared, but the surge tanks are vented to atmosphere. Although the vent gas flowrates are small, the medium oil and phenolic water surge tank vent gases contain relatively high concentrations of sulfur species, as shown in Table 2-1.

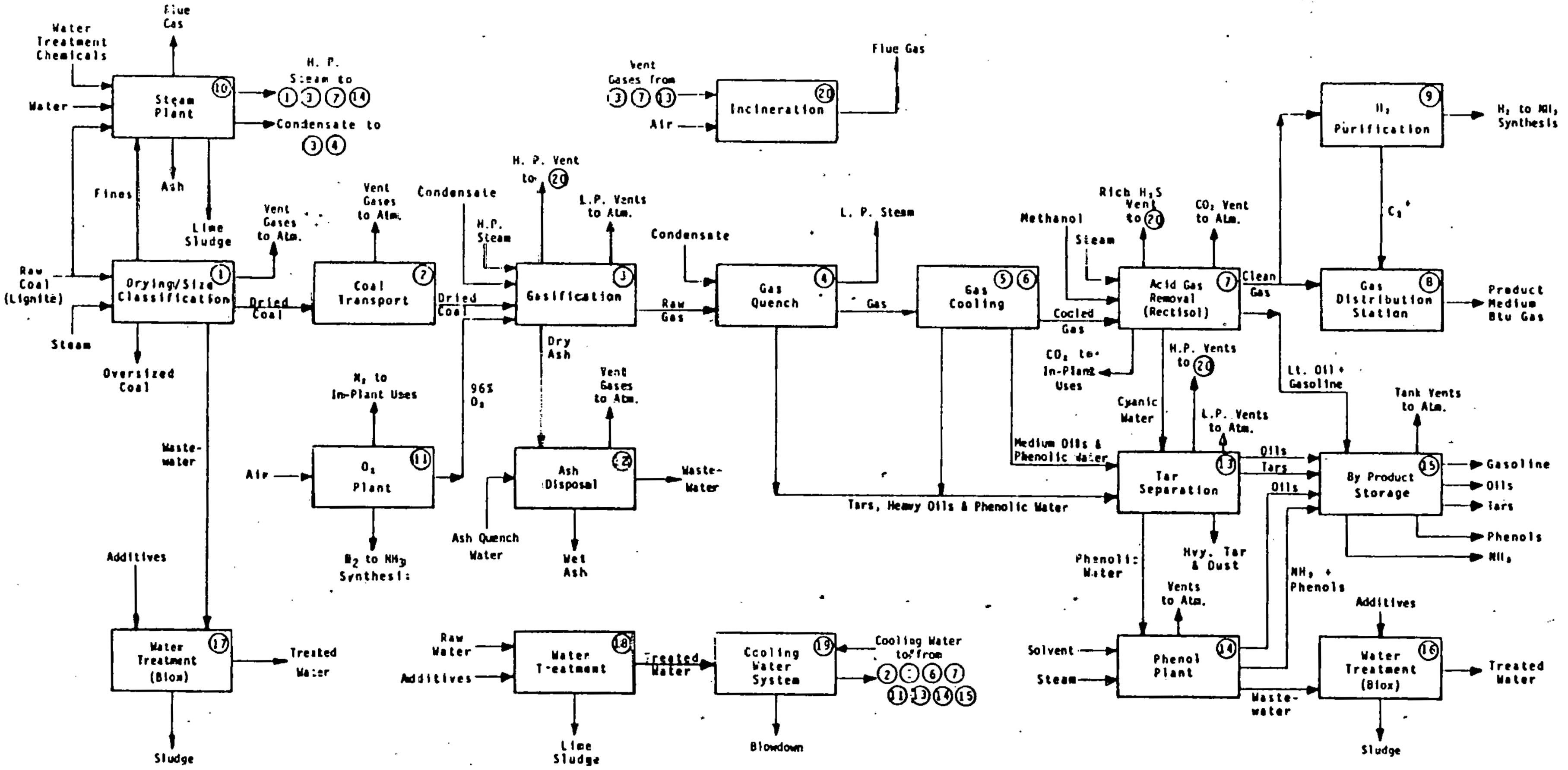


Figure 2-1. Process block flow diagram.
Kosovo Lurgi Gasification Facility, Yugoslavia.

TABLE 2-1. GASEOUS EFFLUENT ANALYSES (Ref. 2) KOSOVO LURGI GASIFICATION FACILITY, YUGOSLAVIA*

	Low Pressure Lock Hopper Vent Gas	High Pressure Lock Hopper Flare Gas	Medium Oil Tank Vent Gas	Phenolic Water Surge Tank Vent Gas	Phenosolvan Stripper Vent Gas	Rectisol Sulfur Removal System		
						Cooled Inlet Gas	H_2S-Rich Off-Gas to Flare	CO_2-Rich Off-Gas to Vent
Estimated Flow Rate (SCFM)	22	225	30	22	225	10,200	1,500	3000
Fixed Gases (vol. %)								
H_2	34.0	32.0	-	-	-	36.1	-	0.8
O_2	0.7	0.2	0.9	13.9	9.0	0.6	0.5	0.1
N_2	2.5	6.1	3.4	53.0	58.0	1.6	1.4	0.3
CH_4	9.4	11.0	7.6	0.2	-	13.0	4.2	0.9
CO	9.3	13.0	-	-	-	13.0	2.6	-
CO_2	42.0	37.0	86.0	29.0	32.0	33.0	86.0	94.0
Sulfur Species (ppm)								
H_2S	700	1100	13,000	1900	7500	4,700	23,000	4.6
COS	170	300	400	-	-	80	560	0.5
CH_3SH	270	420	1,000	680	150	570	4,300	8.5
C_2H_5SH	90	270	480	420	30	100	740	3.5

*This table provides a November 1978 listing of the larger gaseous effluent streams, based on single point analytical measurements which may not be representative of long-term sampling results.

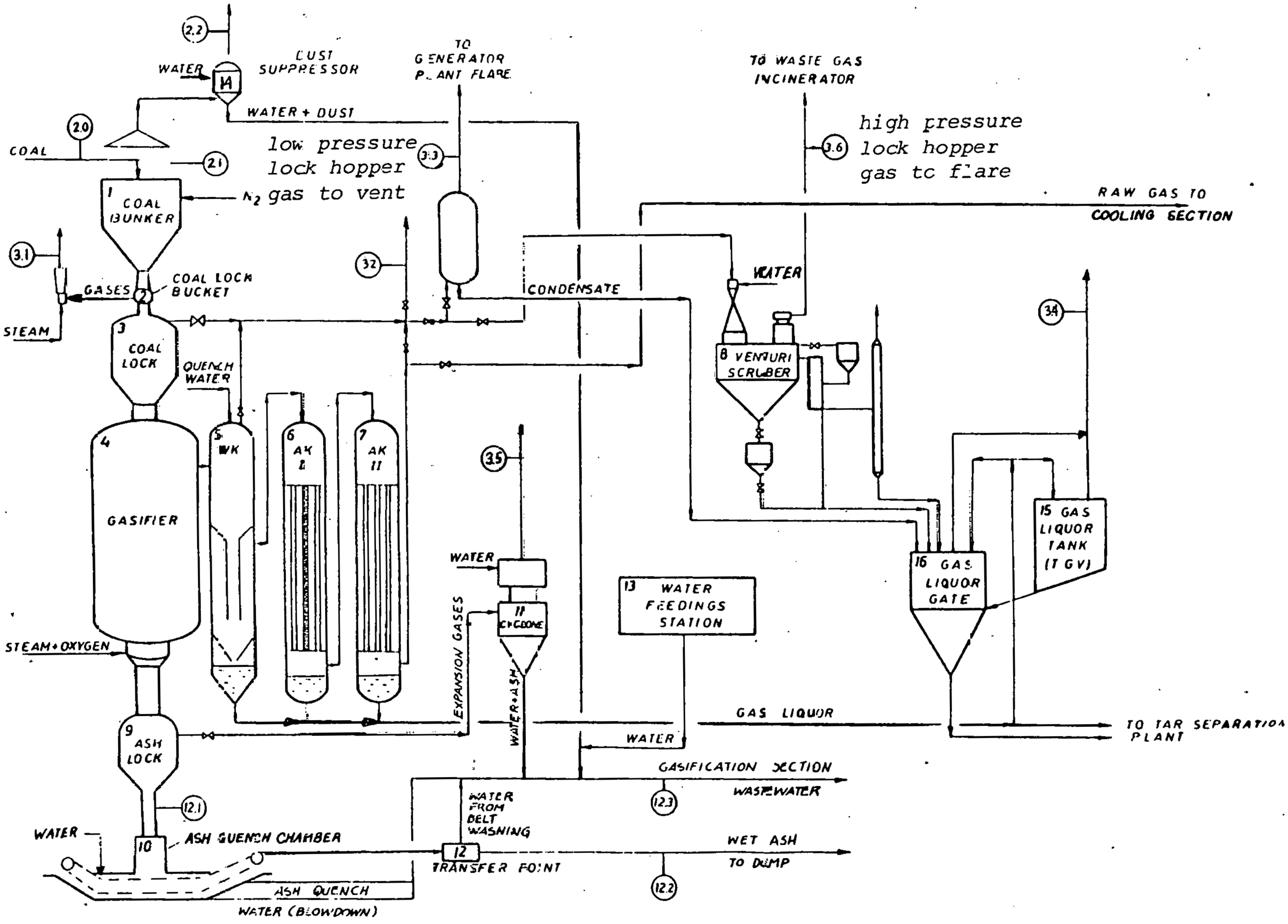


Figure 2-2. Lurgi coal gasification process schematic - Kosovo Combine, Yugoslavia.

Another gaseous effluent stream which is significant at Kosovo is the phenosolvan unit condensate stripper vent. This stream results from the steam stripping of process condensate upstream of the phenol plant ether extraction section. As would be expected, this stream was found to contain acid gases and a variety of other components contained in the process gas liquor which is discharged from the tar separation section.

One of the most significant sources of gaseous emissions at Kosovo is the sulfur removal section. Since the Kosovo Rectisol unit is a selective (Rectisol II) acid gas removal process, a CO_2-rich stream which normally contains minor amounts of H_2S and other sulfur species is generated along with an H_2S-rich stream which should contain most of the other acid gases and sulfur species. The CO_2-rich stream is vented directly to the atmosphere at Kosovo. This same approach has been proposed in several conceptual U.S. plants. The initial 1978 sampling results indicate that this would not be a serious problem, except perhaps during upset operating conditions. Components other than CO_2 which were found in the CO_2-rich vent gas included methane and other light hydrocarbons (which may present hydrocarbon emission problems in some areas of the U.S. due to the relatively large flow rate of this stream). Minor amounts of H_2S and mercaptans were also found in this stream.

The H_2S-rich gas stream generated from the Rectisol unit is a very significant gaseous effluent. At Kosovo, this stream is flared. In the U.S. it is generally preferred to incorporate a treatment process which produces elemental sulfur, such as Claus or Stretford. However, there are potential problems with this approach which are indicated by the Kosovo sampling data. For example, the CO_2 content of this stream may be too great to permit the economical use of a Claus system. Also, the presence of methyl and ethyl mercaptans and hydrocarbons in this stream could result in residual sulfur or hydrocarbon emissions. Specifically with respect to the sulfur species which were analyzed, mercaptan levels appear to be at least as great a source of concern as residual H_2S which penetrates a sulfur removal and recovery system.

In a U.S. gasification facility, most of the gaseous emissions which have been identified at Kosovo would be collected and incinerated in on-site steam generators or recompressed and recycled back into the process. Further work needs to be done to characterize the fate of sulfur species using these two approaches. In addition, potential problems which may be caused by mercaptans, COS, trace hydrocarbons, and CO_2 diluent in the H_2S-rich gas stream feeding into a sulfur recovery process need to be identified and resolved. Another unusual feature of the Kosovo Lurgi gasification process is the tendency to produce low sulfur heavy fuels and high sulfur gasoline products. This is shown in Table 2-2, where the lower sulfur content of the heavier by-product fuels may allow on-site use of this material to satisfy auxiliary fuel requirements. The combustion and emission characteristics when burning these materials has not been investigated.

TABLE 2-2. LIQUID BY-PRODUCTS FROM LURGI GASIFICATION KOSOVO COMBINE FACILITY, YUGOSLAVIA* (Ref. 2)

	Heavy Tar + Dust	Tar	Medium Oil	Gasoline
Composition				
C	56.0	81.9	81.2	85.7
H	7.6	8.4	8.9	9.8
N	0.87	1.3	1.0	0.2
S	0.33	0.49	0.71	2.2
Ash	6.6	0.22	0.03	-
O_2	28.6	7.8	8.2	2.1
Heating Value (Btu/lb)	12,300	17,300	17,800	19,300

*The heating value of the feedstock coal is about 10,000 Btu/lb and the sulfur content is about 1.1%.

2.2 Full Scale Lime/Limestone Wet Scrubbers

Poor operating experience and/or failure of full-scale wet scrubbing systems at electric utility sites in the early 1970's has resulted in a growing recognition of the importance of chemical process control. Based on recent studies of full scale systems by the Electric Power Research Institute (EPRI) (Ref. 3) and others (Ref. 4), the most serious operating and control difficulties with wet scrubbers have been scale formation problems caused by inadequate control of the system chemistry. For the six full scale scrubbing systems evaluated in a recent EPRI study, the reliability of pH sensors for reagent feed rate control cannot be overemphasized as one of the most important features of wet scrubbers which have operated successfully. These six systems are identified in Table 2-3.

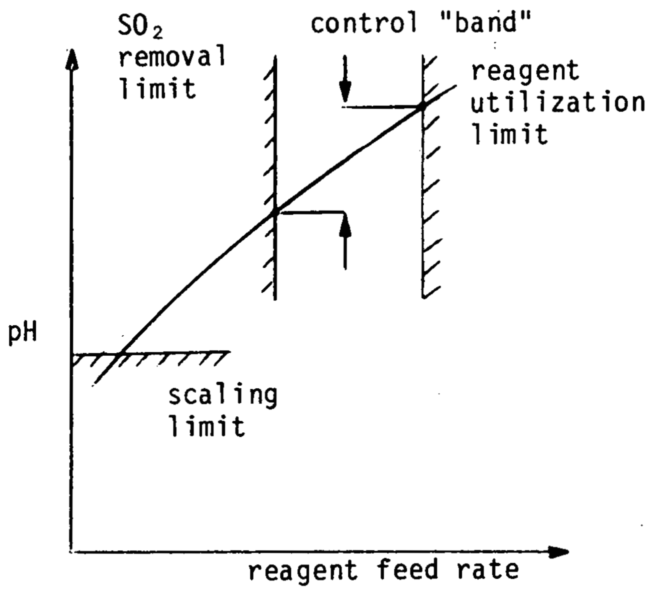
Although reagent feedrate control by pH has some drawbacks, it is the method used in the majority of the lime or limestone scrubber installations, both those which are currently operating and those which are planned. In a typical scheme for controlling reagent feedrate using pH, a stream of scrubber slurry from the recirculation loop is tapped off and passed through a vessel containing the pH sensor. If the inlet SO_2 increases, the pH level in the scrubber slurry drops because of increased SO_2 absorption. When the pH drops below the set point, the controller drives the reagent slurry flow control valve (FCV) to a more open position. The resulting larger flow of reagent causes an increased rate of reaction with acidic species in the scrubber hold tank and brings the scrubber slurry pH back up again. The pH sensor, in turn, monitors the increase in pH level and the controller responds by cutting back on the reagent slurry flow rate. This is a continuous process that can oscillate back and forth in a "band" across the pH set point or remain fairly steady, depending on factors such as the type of reagent, hold tank size, slurry recirculation rate, quantity of SO_2 being removed, and the controller set point.

The width of the pH control band is set by a number of considerations. The minimum pH is constrained by two factors. One factor is the minimum reagent feedrate required to achieve a given degree of SO_2 removal. A second factor is the pH level below which scale formation will tend to occur - this depends on both system design and operating conditions such as inlet SO_2 concentration. The maximum pH in the control band is generally constrained due to reagent utilization factors, which may include $CaCO_3$ scaling in lime systems. These factors are illustrated schematically in Figure 2-3.

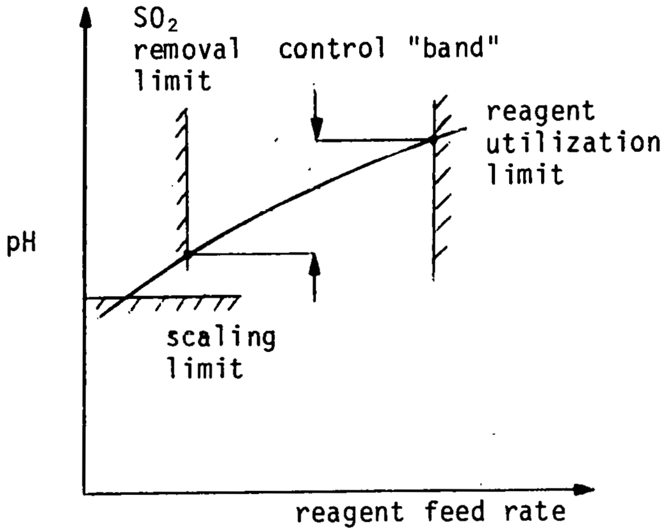
There are two basic types of pH sensors. The dip-type sensor is inserted into a slurry tank and can be manually removed for periodic

TABLE 2-3. TYPICAL FULL-SCALE LIME/LIMESTONE SCRUBBING SYSTEMS (Ref. 3)

Utility/Site	Type of System	MW Rating (MW)	Estimated Gas Flow Rate (SCFM)	Estimated L/G Ratio (gal/MSCF)	Type of Reagent	Type of Reheat
1. Pennsylvania Power Co. Bruce Mansfield Unit 1	Venturi/Absorbers 6 Modules	825	2,500,000	50	Lime	Direct-Fired Burners
2. Southern California Edision Mohave Unit 2	Crossflow Spray 1 Module	170	450,000	20	Lime	Indirect Steam Heaters
3. Kentucky Utilities Green River Units 1, 2, & 3	Venturi/Absorber 1 Module	64	210,000	45	Lime	None
4. Detroit Edison St. Clair Unit 5	Venturi/Absorber 2 Modules	180	490,000	100	Limestone	Indirect-Fired Burners
5. Commonwealth Edison Will County Unit 1	Venturi/Absorber 2 Modules	167	460,000	80	Limestone	Direct Steam Heaters
6. Southern California Edison Mohave Unit 1	Vertical Scrubber 1 Module	170	450,000	35	Limestone	Direct Steam Heaters



Adequate design allows for pH control "overshoot" without causing potential scale formation problems.



Marginal design tends to aggravate scale formation problems due to pH control "overshoot".

Figure 2-3. Illustration of pH control "band" factors.

maintenance and calibration. The flow-through sensor is located in a section of sample piping. A slurry sample must be obtained from a high pressure header, forced through the pH sensor cell, and discharged to a low pressure area. The problem with dip-type sensors is that they cannot be used effectively inside scrubber vessels which must be gas tight. The problem with flow-through sensors is that the sample lines to and from the sensing element frequently plug up and must be back-flushed, cleaned, or periodically replaced, and the sensor elements are subject to high rates of erosion wear.

Maintenance of pH sensors usually involves acid washing followed by recalibration with standard buffer solutions. pH sensor maintenance problems are sometimes aggravated during a scrubber restart after a long outage. This can be attributed to two causes: 1) a low level of slurry solids content during start-up can result in rapid scale formation, and 2) small chunks of physically-dried slurry or flaked scale left over from the outage can plug the pH sensor lines, and may continue to be a problem until all the chunks are dissolved or removed. It is primarily for this reason that dip-type pH sensors sometimes require less maintenance than flow-through pH sensors.

In a lime scrubbing system, the correlation between slurry pH, reagent feed rate, and outlet SO_2 concentration usually responds very quickly to changes in operating conditions. It is even possible in some cases to operate the scrubbing system based on reagent feed rate indication, with periodic checks of slurry pH level.

In a limestone scrubbing system, however, the presence of solid-phase alkalinity ($CaCO_3$) acts to cause a relatively high degree of buffering, so that the relationship between the pH level and outlet SO_2 concentration is less well-defined. Scrubber operators have noted that the degree of excess alkalinity in limestone slurry can be estimated based upon the rate of response of a pH control system. If there is too much excess alkalinity, then the pH of the slurry will not change very rapidly, regardless of the set point on the pH controller. If the slurry system is depleted from excess alkalinity, then the slurry pH will respond rapidly to manual adjustment in the pH set point. These symptoms can also be observed if the limestone reagent feed rate is recorded on a strip chart. Over a given period of operating time, the response of the pH control system will usually produce characteristic records on the reagent feed rate chart, depending on whether the scrubber slurry contains too much or too little calcium carbonate alkalinity. A typical example is shown in Figure 2-4.

Excesses in reagent feed rate are normally of short duration since the trouble usually can be identified fairly rapidly, or the situation corrects itself. More serious problems occur when the scrubber system has been inadequately designed, and the pH level below which scaling occurs is too close to the pH level required for adequate SO_2 removal. The control "band" between just enough and too much reagent may then be quite narrow, possibly causing the reagent feed control system to oscillate out of control. The major drawback of a system which oscillates out of control is a low pH excursion, which represents inability of the control system to respond quickly enough. Repeated low pH excursions will ultimately result in severe calcium sulfate scale formation, culminating in an extended scrubber outage for maintenance.

Short-term reagent feed interruptions, when not repeated continually, have not caused much trouble. Even with a complete feed interruption, many scrubbers do not necessarily have to be shut down immediately. Depending on the size of the hold tank and the operating conditions at the beginning of an upset of this nature, scrubber operation can be continued for a matter of hours in many cases. This is shown in Table 2-4 where it is seen that a reagent feed interruption of 5 to 7 hours was tolerated in a limestone system without a load reduction. In the lime cases, the system chemistry is much less highly buffered, but even so, interruption time of about one hour has been tolerated. (The 4 hour interruption at Green River was effectively less than 4 hours on a "typical" basis because the 30 minute residence time in the scrubber hold tank is not typical for many scrubber systems.) It is important to note that in all these cases, control of the system chemistry was recovered in relatively short times (*i.e.* 0.5 to 1.3 hours) following resumption of reagent feed to the system. Although SO_2 removal presumably dropped off, in none of the tests were there any adverse effects such as scaling or limestone blinding.

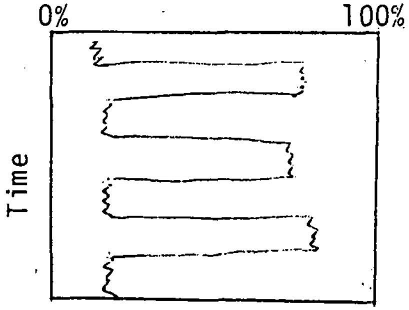
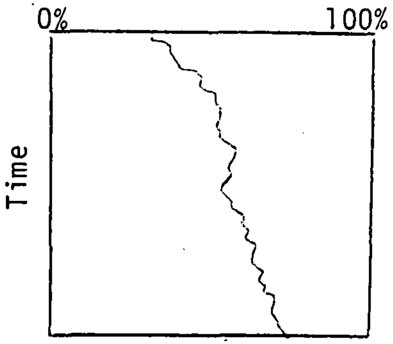
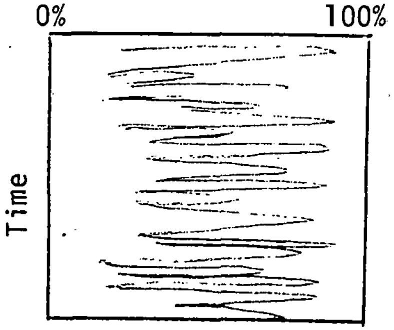
	Observed Condition	Required Operator Action
	Normal: Rate of pH change with time is at a medium level. The feed is held "off" or "on" for relatively long periods and shifts rapidly from one condition to the other.	None
	Excess solid phase alkalinity: Rate of pH change with time is so low and the system is so highly buffered that the flow control valve responds very sluggishly.	Lower pH control set point to reduce absorbent feed rate. Excess condition may be caused by load reduction, drop in sulfur content of coal, and/or accidental absorbent overfeeding.
	Insufficient solid phase alkalinity: Rate of pH change with time is so fast and the system is so starved for absorbent that the flow control valve responds too rapidly.	Raise pH control set point to increase absorbent feed rate. Deficient condition may be caused by increase in load, increase in sulfur content of coal, or underfeeding of absorbent.

Figure 2-4. Method of adjusting pH set point using limestone feed rate and solid phase alkalinity variations (Ref. 4).

TABLE 2-4. TESTS OF REAGENT FEED INTERRUPTIONS (Ref. 4)

Facility	Hold Tank Outlet pH at Start	Length of Interruption, hrs.	Hold Tank Outlet pH When Reagent Feed Resumed	Time Required to Reach Starting Value of pH, hrs.
St. Clair (limestone)	6.0	7.0	4.6	1
Mohave Horizontal (limestone)	5.8	5.5	4.6	1.3
Green River (lime)	5.2 (scrubber outlet)	4.0	3.9	NA
Mohave Horizontal (lime)	6.9	0.8	4.0	0.5

It is concluded that wet scrubbing system problems which involve loss of chemical control and severe scale formation can usually be attributed to a spiralling sequence of events: scale formation leads to sensor malfunction, and sensor malfunction results in loss of chemical control; loss of chemical control then leads to scale formation which is followed by sensor malfunction, etc. The chemistry of lime or limestone scrubbing is quite complex. There is a need to conduct further investigations of scrubbing chemistry in areas such as control of sulfite oxidation, effect of organic additives and selected dissolved salts on scale formation, and effectiveness of new reagent feed control configurations.

2.3 Spray Dryer Plus Baghouse Systems

Due to the operating and maintenance problems which have been observed with wet scrubbers, several dry scrubber process configurations involving spray dryers for flue gas SO_2 removal are being installed on commercial coal-fired generating stations in the United States. The dry scrubbing approach also offers the advantages of zero or little flue gas reheating requirements, and the solid waste material is discharged as a powder which can be pneumatically conveyed. A list of the commercial plants currently proceeding with the design and construction of full-scale dry scrubbing equipment is provided in Table 2-5.

TABLE 2-5. COMMERCIAL STATUS OF SPRAY DRYERS FOR SO_2 CONTROL IN THE UNITED STATES

Utility/Plant/Site	Successful Bidder	A-E or Evaluator	MW Capacity & No. of Modules	Start-Up Date
1. Basin Electric Antelope Valley Beulah, ND	Joy/Niro (lime reagent)	Stearns-Roger	435 MW 5 modules	1981
2. Basin Electric Laramie River Wheatland, WY	Babcock & Wilcox (lime reagent)	Burns & McDonald	600 MW	1983
3. Otter Tail Power Coyote Station, ND	Rockwell International/ Wheelabrator-Frye (soda ash reagent)	Bechtel	410 MW	1981
4. Niagara Mohawk Huntley Station, NY	Atomics International	ESEERCO[1]	80 MW	TBD[2]

[1] ESEERCO stands for Empire State Electric Energy Research Corporation, which is solely funded by private utility companies including Consolidated Edison, New England Electric Power Service Company, Niagara Mohawk Power Company, and others.

[2] The ESEERCO project features a molten salt regeneration system and the current cost estimate is about $640/kW - about five times as much as a Joy/Niro system including dryer and baghouse. The Joy/Niro bid for Antelope Valley was reported to be $115/kW.

A typical dry scrubbing process block flow diagram is shown in Figure 2-5, and typical lime slurry SO_2 removal results are presented in Figure 2-6 as a function of reagent utilization and flue gas temperature drop across the spray dryer (Ref. 5). Normal spray dryer outlet temperatures are in the 160°F to 170°F range to provide sufficient operating margin above the saturation temperature. The reagent feed rate can be controlled by the spray dryer outlet temperature. If the air preheater rotating speed is reduced, the spray dryer inlet temperature increases, and the degree of SO_2 removal increases by virtue of improved liquid/gas contacting when more liquid can be tolerated in the feed slurry (Ref. 5).

The percentage reagent utilization can usually be increased by recycling a portion of the fly ash plus reaction products from the baghouse and/or spray dryer bottom cone. In some cases where high SO_2 removal efficiency is required, the amount of fresh lime reagent needed can be reduced by a factor of two when fly ash recycle techniques are employed. Obviously, this depends on the chemistry of the fly ash as well as the specific nature of the fly ash recycle control system. Many dry scrubbing concepts are still being developed and tested, and most of the process control schemes are still considered proprietary at this time.

2.4 Discussion

As shown in Table 2-6, there are fourteen air-blown, low pressure coal gasifiers in operation or under construction in the United States at this time. This amounts to a coal processing capacity of about three Lurgi gasifiers, and cannot be considered a significant large-scale use of coal gasification in the United States.

Two prototype-scale (*i.e.* 150 TPD) entrained-bed gasifiers have been operated in West Germany since early 1978. Both systems are oxygen-blown, slagging-type gasifiers that do not produce tars, oils, or phenols typical of Lurgi or low-pressure, air-blown coal gasification systems. One of these prototypes uses the Texaco coal gasification process (Ref. 7) and the other is a high pressure adaptation of the original K-T process (Ref. 8). Both of these newer coal gasification processes offer the promise of high

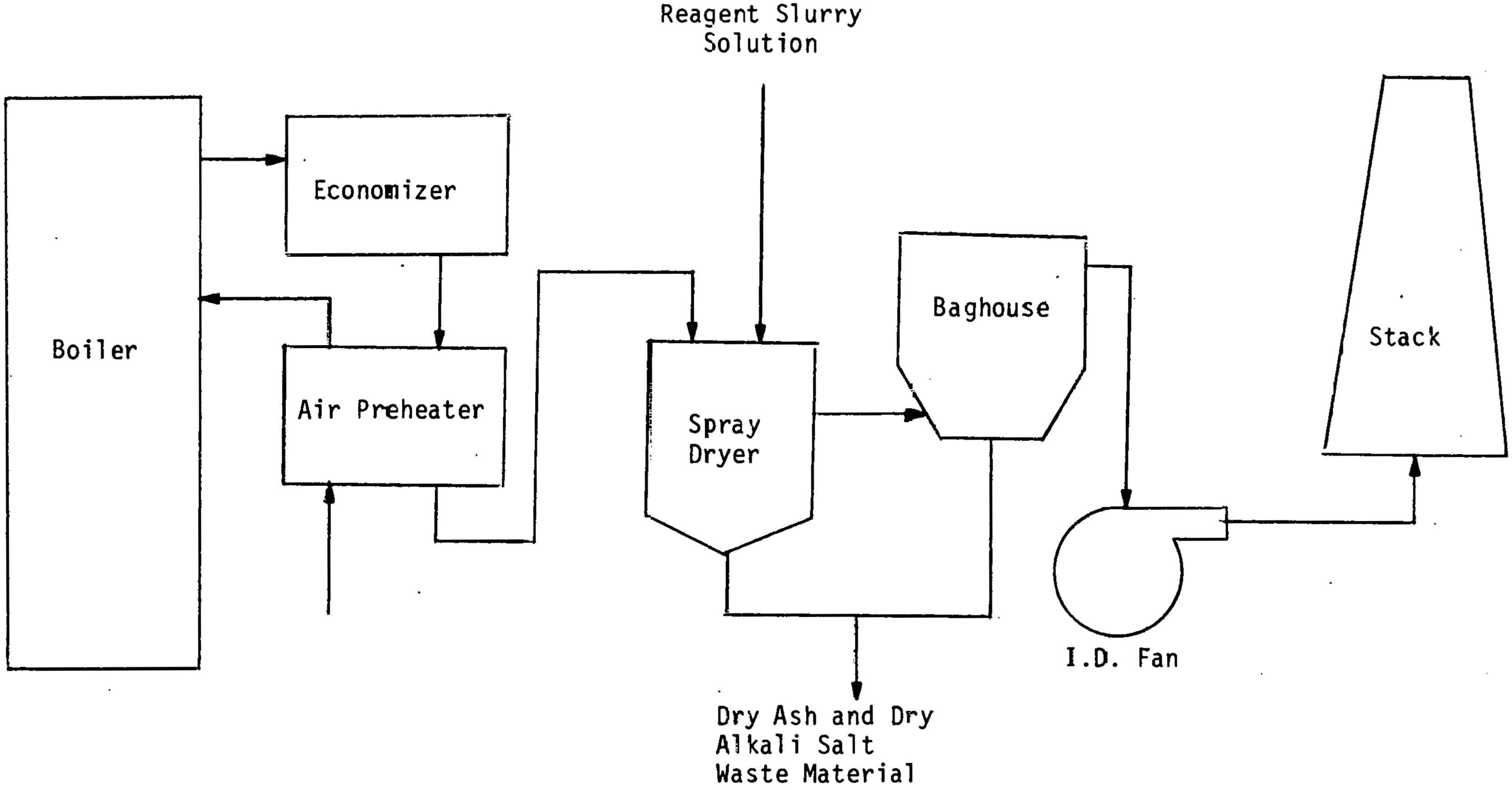
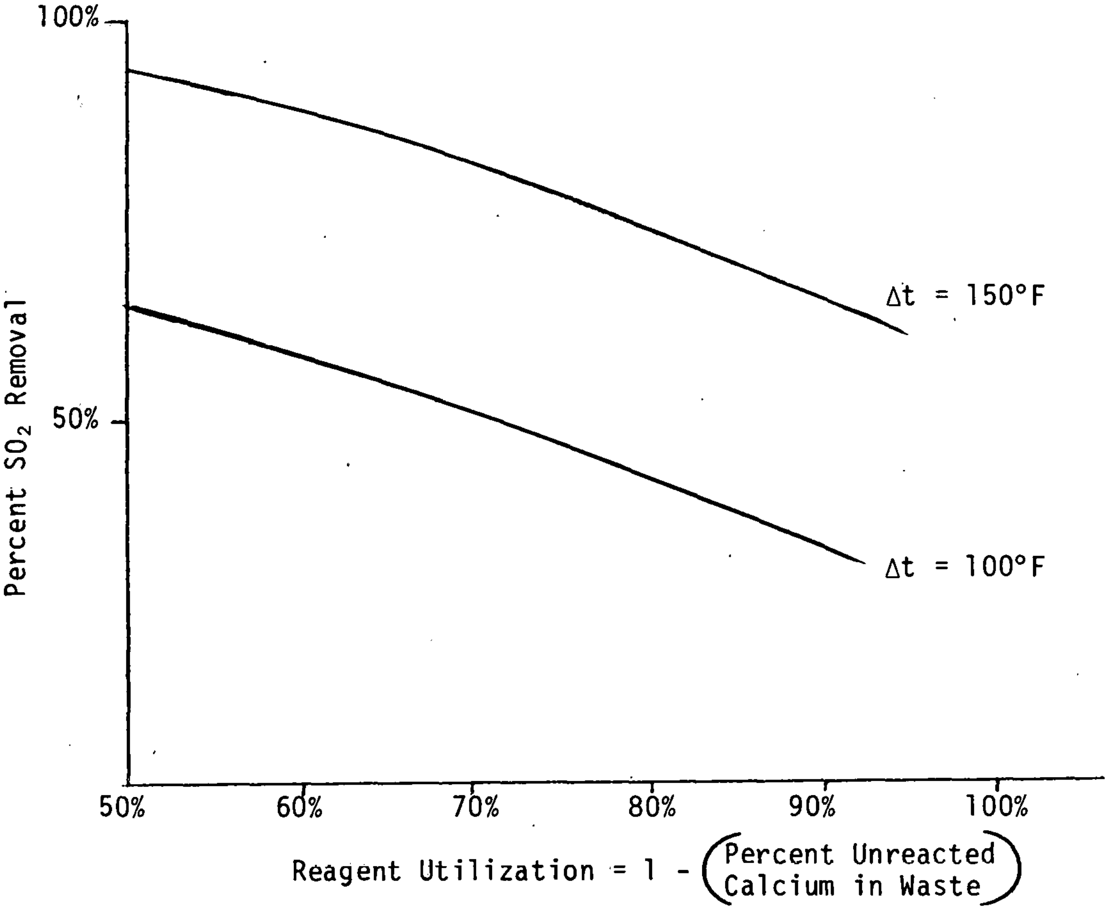


Figure 2-5. Flow diagram - spray drying with baghouse collection.



Note: A higher Δt means that the solids content of the feed slurry can be reduced at the same reagent utilization. Thus, the reagent particles get dispersed better and SO_2 removal increases.

Figure 2-6. Typical dry scrubber results with lime reagent (Ref. 5).

TABLE 2-6. CURRENT AIR-BLOWN, LOW-PRESSURE COAL GASIFICATION FACILITIES IN THE UNITED STATES (Ref. 6)

Operating Company and Location(s)	Number of Gasifiers	Gas Purification Process	Start-Up Date
Glen-Gery Brick Co.			
● York, PA	2	Hot Cyclone	Currently operational
● Reading, PA	2		
● Shoemakersville, PA	1		
● Watsontown, PA	1		
National Lime & Stone Co.			
● Carey, OH	2	Hot Cyclone	Currently operational
Can Do, Inc.			
● Hazeltown, PA	2	Hot Cyclone	1979
Bureau of Mines			
● Fort Snelling, MN	1	● Hot Cyclone ● SO_2 Scrubbers	1978
Pike County, Kentucky	2	● Hot Cyclone/ESP	1979
● Pikesville, KY		● Stretford Sulfur Removal	
Aluminum Refinery Client			
● Pennsylvania site	1	Hot Cyclone	1979

pressures, reduced environmental cleanup problems, and simplified process control suitable for integration with combined cycle power plants. Texaco, Inc. and Southern California Edison Company have recently announced plans to construct a 1000 TPD coal gasifier module leading to demonstration of the integrated gasification plus combined cycle process (Ref. 9). Such a demonstration project would help identify the high degree of sulfur removal and recovery which is anticipated to be feasible.

3.0 CONCLUSIONS

- Although pressurized gasification will be required for the production of any synthetic fuels from coal (including coal liquefaction), the United States lags far behind several other countries in proceeding with the necessary demonstration projects.
- Despite encouraging trends to develop and demonstrate a synthetic fuels industry, there will be very little in the way of large-scale synthetic fuel production prior to the 1985 to 1990 time frame.
- It is anticipated that direct combustion of coal in a boiler, followed by wet or dry flue gas desulfurization, will continue to be the primary method of utilizing coal in the United States until well past the year 2000.

REFERENCES

1. White, W. R., O. W. Hargrove, D. G. Jones, and G. A. Kunberger, Assessment of Advanced Coal-Based Technologies for Use in California, Radian Report DCN 79-202-329-04-05, August 1979.

2. Bombaugh, K. J., and W. E. Corbett, "Kosovo Gasification Test Program Results--Part II, Data Analysis and Interpretation", presented at 4th Annual Symposium on Environmental Aspects of Fuel Conversion Technologies, Hollywood, Florida, April 17-20, 1979. Prepared at Radian Corp., Austin, TX.

3. Jones, D. G., A. V. Slack, K. S. Campbell, Lime/Limestone Scrubber Operation and Control, EPRI Report FR-627, October 1978.

4. Jones, D. G., O. W. Hargrove, and T. M. Morasky, "Lime/Limestone Scrubber Operation and Control," APCA Paper No. 79-23.6, presented at the 72nd APCA Annual Meeting, Cincinatti, OH, 24 June 1979.

5. Felsvang, K., "Results of Pilot Plant Operations for SO_2 Absorption," presented at Joy, Western Precipitation Division Seminar, Tamarron Resort, Durango, CO, 20 May 1978.

6. Thomas, W. C., and G. C. Page, "Environmental Assessment Report for Wellman-Galusha Gasification Systems," presented at 4th Annual Symposium on Environmental Aspects of Fuel Conversion Technologies, Hollywood, FL, April 17-20, 1979, prepared at Radian Corp., Austin, TX.

7. Specks, R., J. Laughoff, and B. Cornils, The Development of a Pulverized Coal Gasifier in the Prototype Phase Using the Texaco System, Ruhrkohle AG and Ruhrchemie AG publication, West Germany, July 1978.

8. Van der Brugt, M. J., and H. J. Kraayveld, "Technical and Economic Prospects of the Shell-Koppers Coal Gasification Process," presented at the 175th American Chemical Society Meeting, Industrial and Engineering Division, Anaheim, CA, 16 March 1978.

9. Cool Water Coal Gasification Project: An Opportunity and a Challenge, joint publication by Southern California Edison Company and Texaco, Inc., 30 July 1979.

Correlating Process Parameters and Tar/Water Production for a Slagging Fixed-Bed Gasifier

G. G. Mayer, D. R. Hajicek, and P. G. Freeman
Grand Forks Energy Technology Center

INTRODUCTION

The Grand Forks Energy Technology Center (GFETC) is operating a modified version of a lurgi fixed-bed gasifier. Major emphasis of the research program is to gather effluent data. As part of the program, a gas chromatographic (GC) system was developed to determine quantities of water and tar components in the hot product gas stream. The system described in this paper has successfully sampled and analyzed a high moisture, low temperature gas stream, generated by gasification of a high moisture lignite. Results obtained by the GC are correlated with results obtained with a side stream sampling system. A further comparison between results from the side stream samples and results for composite samples from a down-stream spray washer is presented in a companion paper at this Symposium (5).

GASIFICATION PROCESS

A flowsheet of the pilot plant is shown in Figure 1. Recent publications (1,2,3,4) have discussed the test equipment and procedures in detail. A brief summary will be provided here.

The test coal is introduced into the gasifier through a lock hopper. As the coal decends through the shaft, it is heated by countercurrent flow of hot gases coming from the reaction zone. Drying, devolatilization and gasification occur in distinct zones in the coal bed. The coal reacts with the steam-oxygen mixture that is injected into the hearth section. Gasification occurs at temperatures of approximately 1700°C, completely consuming the coal and leaving only molten ash. The molten ash drops down into a water bath in the lower lock hopper, producing a frit resembling coarse sand which is periodically removed. The product gas leaves the top of the gasifier and enters a recycle liquor spray washer where water vapors, tar, oil and dust are removed. The accumulated liquor in the spray washer system is periodically drained into a holding tank at atmospheric pressure. After passing through the spray washer, the gas is further cooled in a heat exchanger, depressurized, demisted, metered, and flared. A typical gas composition is 58% CO, 29% H_2, 5% CH_4, and 7% CO_2, with small amounts of C_2-C_4 hydrocarbons.

Gasification test parameters include operating pressure, oxygen rate, oxygen to steam ratio, moisture content of coal, and type of coal gasified. The raw product gas stream is sampled periodically during each gasification test to determine the quantities of tar and water in the gas and how variations of process parameters affect the production of the components. In the test program operating pressures have ranged from 100 to 400 psig, the oxygen rates have ranged from 4000 to 6000 scfh, the molar oxygen steam ratios have ranged from 0.9 to 1.1, and fuel moistures have ranged from 20 to 38 percent.

SAMPLING

Collecting representative and reproducible samples of effluents from the gas offtake at the top of the gasifier presents special problems. Samples must be collected at pressures up to 400 psig and at an approximate steady-state temperature of 300°F. This effluent stream contains a multi-phase combination of product gases, water vapor, organic vapors, tar and water aerosols, and entrained particulates. The sampling probe at the gas offtake consists of ½" OD by ¼" ID tube bent into a 90° angle to face the product gas stream. The leading edge of this probe is tapered down at a 45° angle.

SAMPLING METHODOLOGY

A major effort has been directed toward developing and enlarging the capabilities for sampling and characterizing liquid effluents. To accomplish this, several forms of sampling have been developed. The methods that will be described in this paper will include side stream sampling through a condensation train and on-line sampling through a heated GC. Both these methods, but particularly the on-line sampling, provide an opportunity to observe the short-term changes in effluent yield and composition that result from non-steady state operation due to coal charging.

Side Stream Sampling

Side-stream sampling (5) allows the collection of samples representative of selected coal charging cycles within a gasification test. In side stream sampling, a portion of the raw product gas stream from the gas offtake is passed through a sampling system to remove the condensibles and particulates from a measured quantity of gas. Major components of the present system, shown in Figure 2, are an automatic pressure control valve, a high pressure and low pressure cyclone, two heat exchangers, a cryogenic trap and a gas meter. The automatic pressure control valve regulates the flow of gas sampled and reduces the sample pressure to approximately 18 psig. The high pressure cyclone is located before the control valve and removes water and tar aerosols that could plug the valve. The low pressure cyclone removes the additional effluents condensed out during pressure let-down. The two heat exchangers condense out water and light oils down to 1°C. The cryogenic trap is used to remove water and some of the light oils from the gas stream at temperatures below 0°C.

On-line Sampling

The on-line sampling, employing GC's, provides the capability of establishing rapid and short term variations in tar-oil and water production rates. Since sampling intervals can be as short as five minutes, a fairly complete pattern of change can be established over the course of the nominal hour coal charging cycle. The GC system used for analysis is flexible in that a variety of effluent components can be determined by selecting an appropriate set of analytical parameters such as column support, stationary phase, temperature, and flow rate. The portability of this system allows it to be used at several different sampling locations during a gasifier run, or it can be taken to the laboratory for calibration and developmental work.

A schematic of the sampling system is shown in Figure 3. The insulated stainless steel sample lines are purged continuously with the sample stream to stabilize sampling conditions. Thermocouples are strategically located to monitor temperatures of the effluent stream throughout the sample line. Flow rates are manually controlled by adjusting to a constant pressure. A Valco* eight-port switching valve with .5 ml sample loops is used to obtain a quantitative sample which is carried into the GC column with helium carrier gas. The temperature of this sampling system is maintained above 110°C to prevent condensation and plugging.

The gas chromatographic system for monitoring tar production, shown in Figure 4, consists of a Gow-Mac series 150 gas chromatograph and a HNU model PI-51 photoionization detector. A Spectra-Physics Autolab System I computing integrator and a Honeywell Electronic 196 recorder provide the data handling capability. The photoionization detector uses a 10.2 electron volt ultraviolet source. This detector does not respond to permanent gases, water, or most low molecular weight hydrocarbons because of their high ionization potentials.[6] As a result, detection of organics is simplified because of the relatively small quantity of tar - nominally less than 0.006 volume percent - in relation to gas and water in the effluent streams.

In order to meet the criteria of multiple analysis within a data period the on-line GC is not intended to provide a detailed component-by-component analysis. Rather, a simulated distillation is obtained, which can be accomplished in a much shorter time period. A 6 ft x ¼" O.D. column packed with 5% Apiezon L on 80/100 Anakrom SD was selected because it provides a good boiling point distribution of the tar components. Instrumental parameters used were: inlet temperature 170°C, detector temperature 170°C, helium carrier flow of 20 ml/min at 150°C column temperature.

The gas chromatographic system for monitoring water production consists of a Gow-Mac series 150 gas chromatograph and a thermoconductivity detector. Data handling capabilities are the same as for the tar monitor. An 8 ft x ¼" O.D. Porapak Q column was selected because of the short analysis time and the efficient separation of water from tar components. Instrumental parameters used were: inlet temperature 145°C, detector temperature 145°C, helium carrier flow of 60 ml/min at 125°C column temperature.

* Reference to specific brand names or models is done to facilitate understanding and neither constitutes nor implies endorsement by the Department of Energy.

REPRODUCIBILITY

The precision of the GC system was determined by performing six replicate analyses of a sample of gasification tar. Table 1 shows the average, standard deviation, and relative standard deviation (7) for six observations respectively on the six major peaks. The relativ standard deviation ranged from 1.39 to 5.88 pct.

Samples of the compounds appearing in each of the peaks were obtained by using the same column material and chromatographic conditions in a Varian model 2100 preparative scale gas chromatograph. Analysis of each collected fraction was done with a Dupont model 491B mass spectrometer. The first two fractions consisted of saturated hydrocarbons, which were not identified further. The other four samples contained mixtures of derivatives of benzene, phenol, indene, indane, and naphthalene. Although the separation of compounds is by no means clean, there is a regular progression of boiling points as illustrated in Figure 5.

TAR AND WATER PRODUCTION

The yield of water in the raw product gas was calculated for several runs using North Dakota Indian Head lignite as fuel. Comparisons of this data from the on-line gas chromatograph and the side stream sampler were made. Values obtained from the on-line GC system and the side stream sampling system are given in Table 2; these values agree within 3 to 5 pct.

The yield of tar in the raw product gas was also calculated for pilot plant gasification of North Dakota lignite. The value obtained from the on-line GC system and from the operation of the side stream sampler are given in Table 3; these values agree within 7 to 12 pct.

These estimates of the water and tar yields show good agreement between the two sampling techniques. Tar yields measured by on-line GC were consistently higher than those from the side stream samples; water yields were relatively lower. Consistent results were obtained independent of the operational variables.

EFFECT OF COAL CHARGING ON TAR AND WATER PRODUCTION

In all tests to date it has been necessary to isolate and depressurize the coal lock to replenish the coal supply; therefore the GFETC gasifier has operated in a semi-batch mode. The time required to gasify the amount of coal in the original single lock hopper (about 1100 to 1300 lb) is referred to as a "data period". Depending on operating conditions, a data period lasted from 40 to 70 minutes. The semi-batch operation resulted in cyclic behavior in the gasifier. This is particularly evident in the offtake temperatures and product gas moisture content as shown in Figures 6 and 7. When the coal lock emptied, it was isolated from the gasifier and recharged. During this period (approximately 12 minutes for every hour of operation) the fuel bed in the gasifier continued to descend. Without the moisture content of the coal feed, gas temperatures increased and the moisture content of the gas decreased. The level of coal in the reactor may have dropped into the devolatilization zone causing the rate of devolatilizatior to change. After the coal lock was charged, it reopened and fresh coal immediately filled the top of the bed, reversing the trend in the gasifier heat balance. Gas temperatures immediately decreased, and moisture content of gas increased. Volatiles in the gas stream contacted relatively fresh coal and may have condensed. With a moderately high moisture lignite, the steady state off-take temperature was typically 135°C. During the periodic coal charging; offtake temperatures ranged from 55°C to 500°C.

The tar content of the product gas stream was also a function of the charging cycle, although this was less evident than for the water content. From Figure 8 it can be seen that typical tar production varied between two extremes. Curve A represents tar production as a sinusoidal function of the charging operation without a constant level of tar evolution. Curve B shows tar being produced at a constant rate for some definable period within the data period. Both curves show tar production reaching a maximum towards the end of the data period or around the time of isolation of the coal hopper from the gasifier column. Production of tar reaches a minimum shortly after the hopper is opened and the temperature is at a low.

It is evident that tar production varied within a data period because of the semi-batch operation of the gasifier. To determine whether tar production varied from one data period to another, the relative standard deviations of certain tar fractions were calculated for selected time periods over a number of data periods during a gasification run. These results were compared with the six replicate analyses performed on gasification tar in the laboratory. The two peaks showing the lowest relative standard deviations were chosen for the comparison. Results shown in Table 4 indicate large variations in tar production over the entire course of the gasification test.

Operation is considered to be at steady state conditions when a series of values vary from the data period average by less than ten percent. From Figure 9 it can be seen that with increased pressure and oxygen rate there is a slight trend toward longer periods of steady-state gasifier operation. However, the total amount of time the gasifier is at steady state operation is in the range of only 13 to 32 pct. The dual-lock coal feeding system being installed should eliminate most of the variation caused by the semi-batch operation of the gasifier (4).

CONCLUSION

The on-line GC system provides a method for sampling a multiphase stream of gas and tar aerosols at elevated temperatures and pressures, and for providing a characterization of the tars in the raw gas by an approximate boiling point distribution. A high level of measurement precision and good agreement between GC estimates and side-stream sampler determinations of tar and water production was demonstrated. The large difference in relative deviation between replicates performed in the laboratory and on-stream GC indicates that the gasification process itself was highly variable. The on-stream GC analyses will be used to estimate the success of design modifications in achieving steady-state gasifier operation.

REFERENCES

1. Gronhovd, et al. "Design and Initial Operation of a Slagging Fixed-Bed Pressure Gasification Pilot Plant." BuMines RI 6085, 1952.

2. Gronhovd, et al. "Slagging Fixed-Bed Gasification of North Dakota Lignite at Pressures to 400 PSIG." BuMines RI 7408, 1970.

3. Ellman, et al. "Current Status of Studies in Slagging Fixed-Bed Gasification at the Grand Forks Energy Research Center." Ninth Biennial Lignite Symposium, Grand Forks, 1977.

4. Ellman et al. "Slagging Fixed-Bed Gasification Project Status at the Grand Forks Energy Technology Center." Tenth Biennial Lignite Symposium, Grand Forks, ND, 1979.

5. Hajicek, et al. "Development and Operating Characteristics of a Gas Sampling System for the Grand Forks Energy Technology Center's Slagging Fixed-Bed Gasifier." 1979 Symposium on Instrumentation and Control for Fossil Energy Processes, Denver, Colorado.

6. Driscoll, J. N. "A Photoionization Detector in Gas Chromatography." American Laboratory, 71, Oct. 76.

7. Belz, M. H. Statistical Methods in the Process Industries. John Wiley and Sons, New York, 1973.

Table 1. REPRODUCIBILITY OF SYSTEM OPERATION

Peak	Average Area N=6	Std. Deviation	Relative Std. Deviation
1	5.13	0.17	3.29%
2	15.75	0.22	1.39%
3	16.17	0.59	3.67%
4	21.25	0.75	3.51%
5	10.76	0.63	5.88%
6	30.93	0.49	1.58%

Table 2. WATER YIELD
kg/metric ton (lbs/ton maf coal)

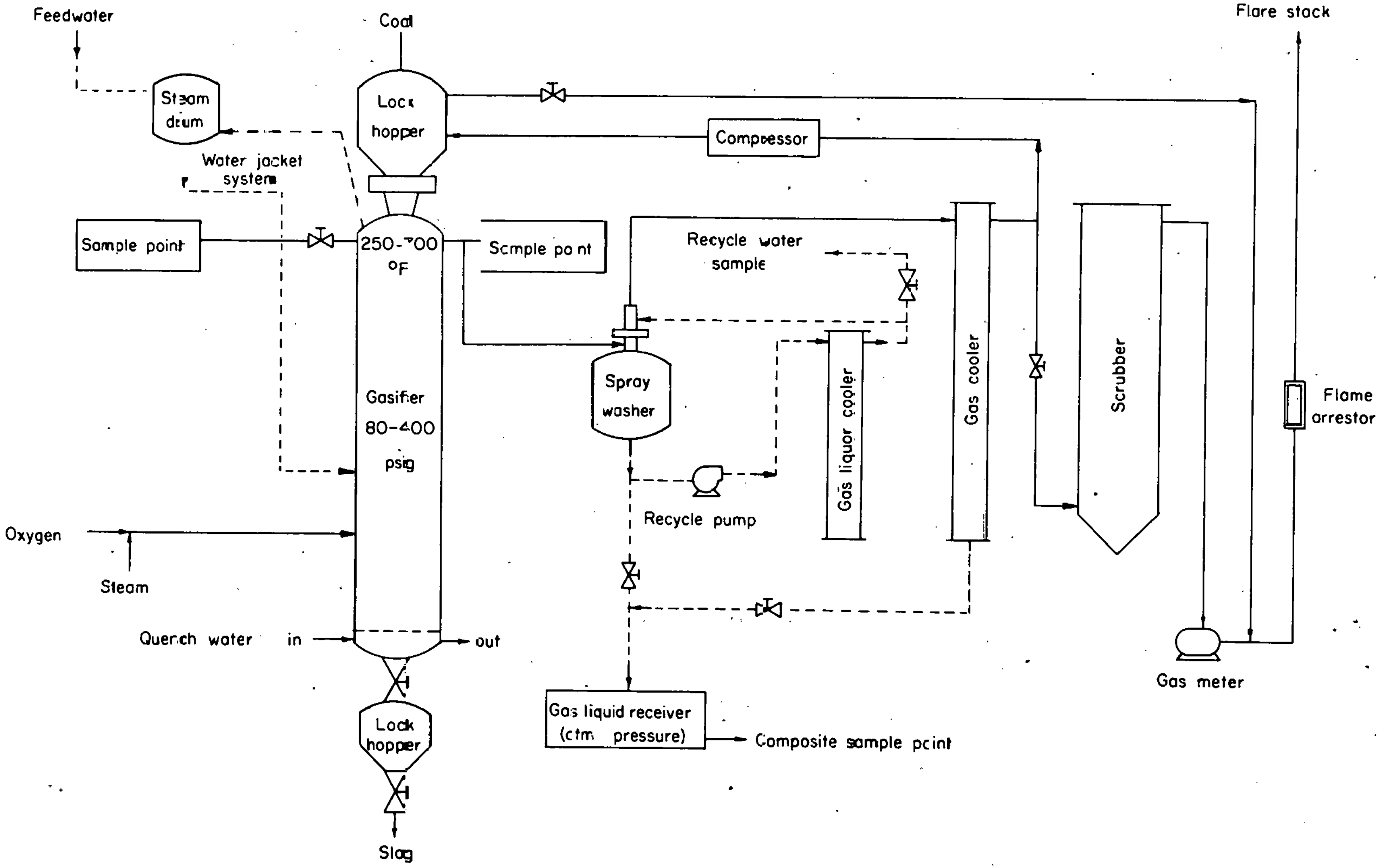
Run No.	On-line GC	Side Stream Sampler
RA-12	465 (930)	490 (980)
RA-14	625 (1250)	640 (1280)
RA-16	385 (770)	400 (800)

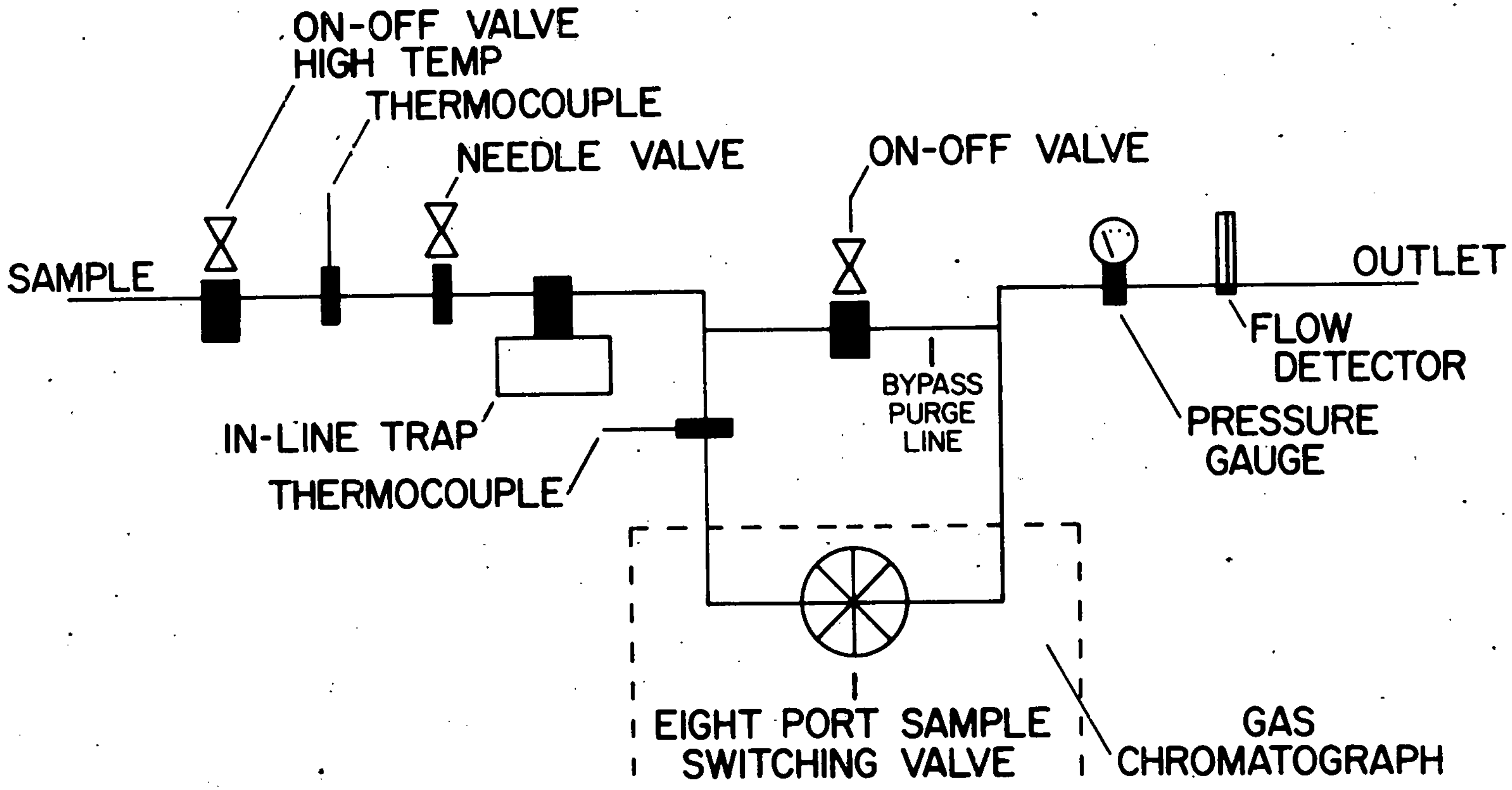
Table 3. TAR YIELD
kg/metric ton (lbs/ton maf coal)

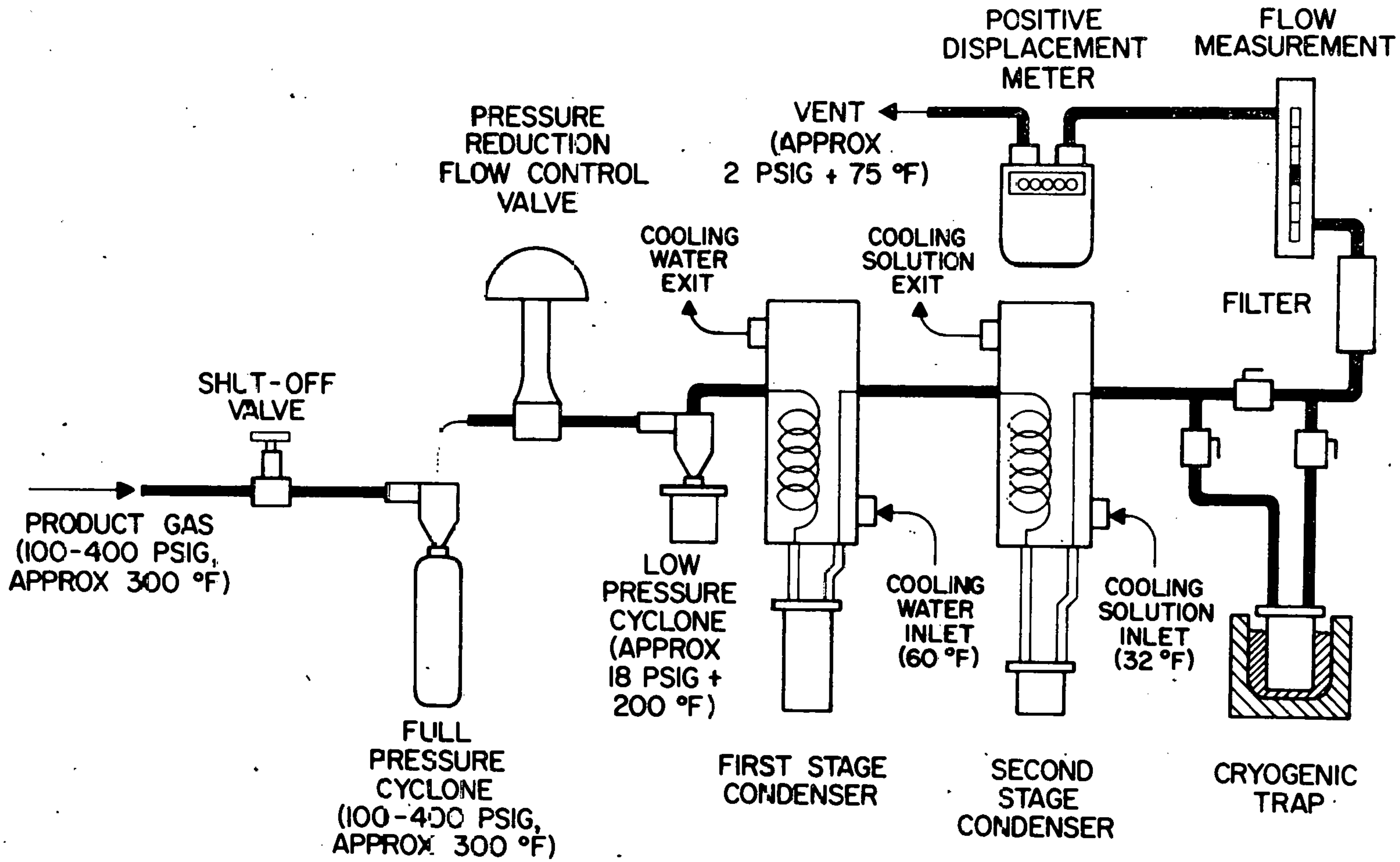
Run No.	On-line GC	Side Stream Sampler
RA-40	37 (75)	33 (66)
RA-52	49 (99)	46 (92)
RA-59	42 (85)	39 (78)

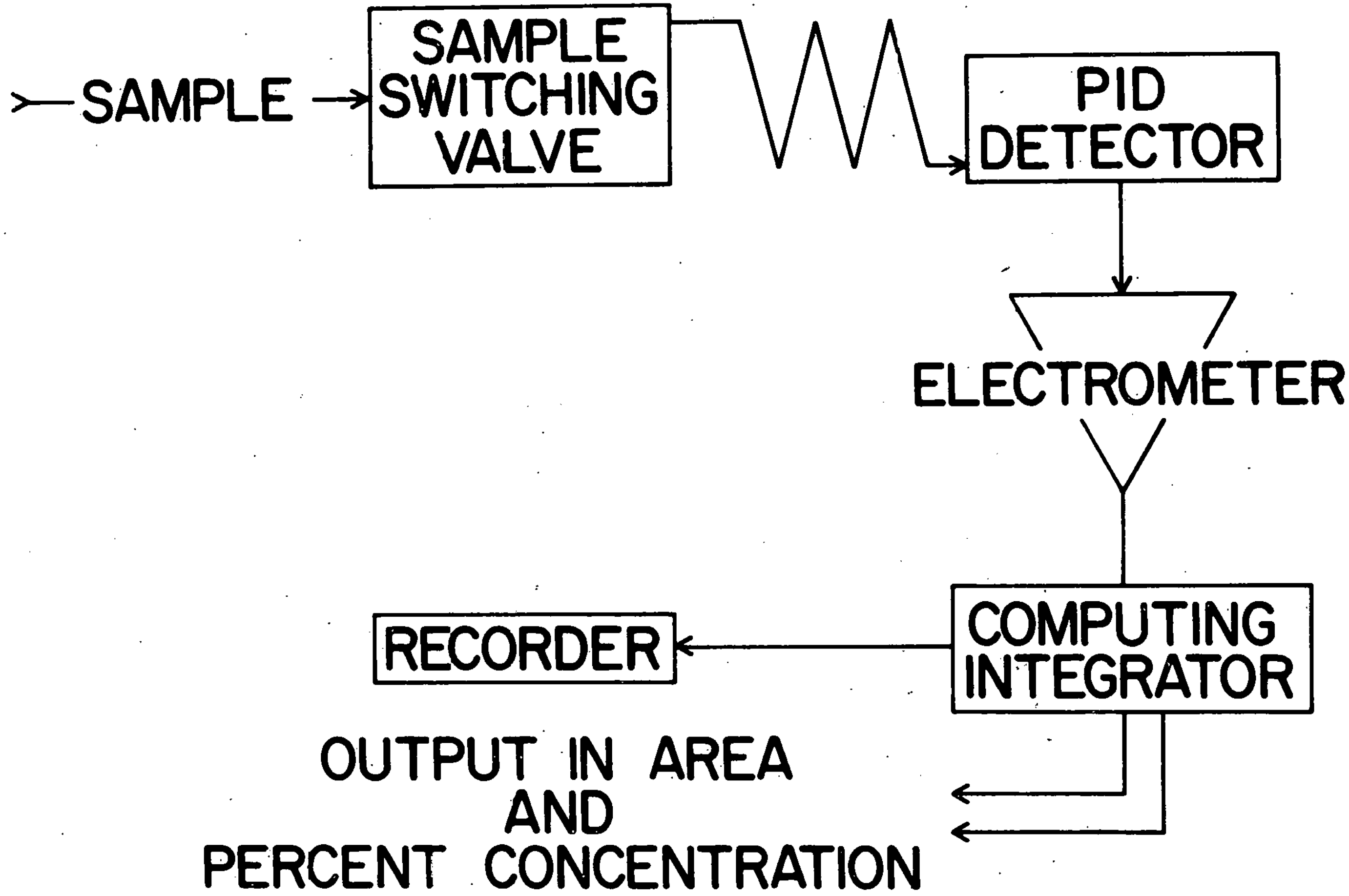
Table 4. RELATIVE VARIABILITY OF TAR ESTIMATIONS BY GC

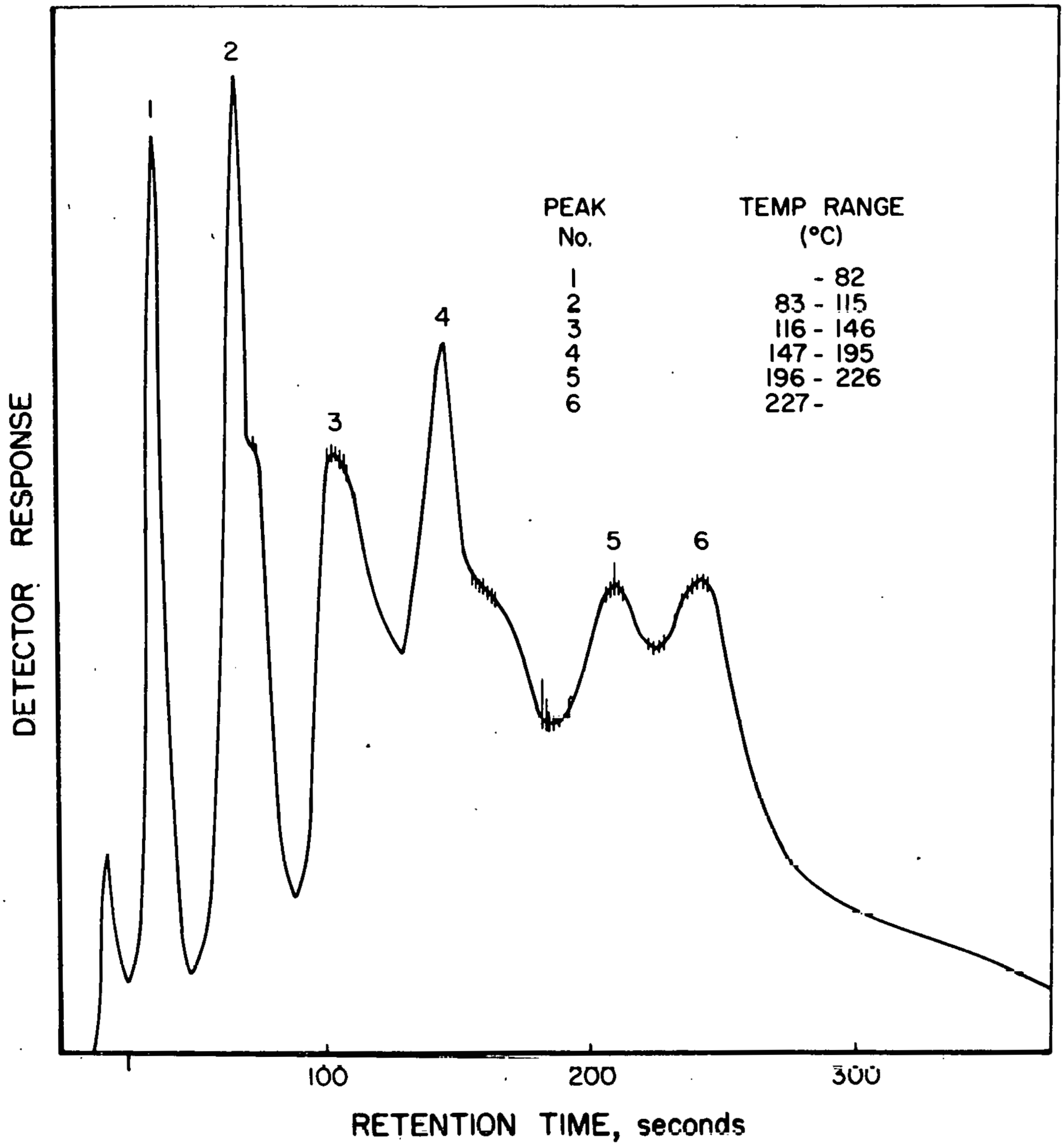
Laboratory	Peak No.	Average	Std. Deviation	Relative Std. Deviation
N=6	2	15.75	0.22	1.39%
	6	30.93	0.49	1.58%
On-line				
N=6	2	5.63	3.29	58.44%
	6	23.04	10.03	43.55%


Feedwater
Steam drum
Coal
Lock hopper
Water jacket system
Sample point
250-700 °F
Sample point
Compressor
Flare stack
Recycle water sample
Spray washer
Gas liquor cooler
Gas cooler
Scrubber
Flame arrestor
Gasifier 80-400 psig
Oxygen
Steam
Quench water in
out
Recycle pump
Lock hopper
Slag
Gas liquid receiver (atm pressure)
Composite sample point
Gas meter

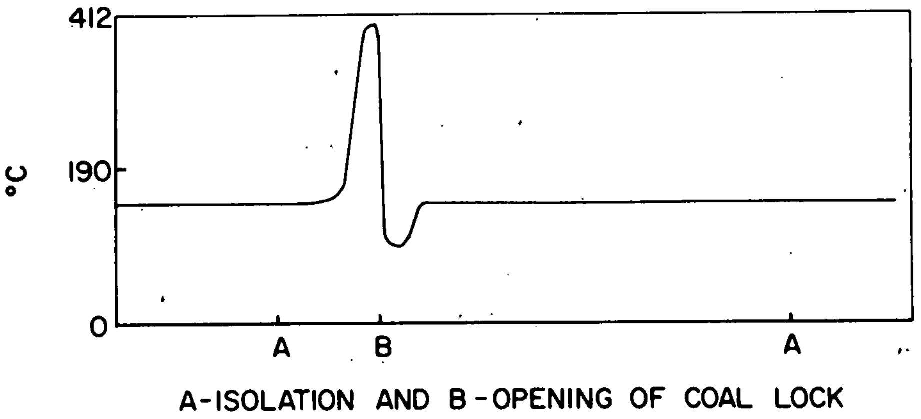

ON-OFF VALVE
HIGH TEMP
THERMOCOUPLE
NEEDLE VALVE
ON-OFF VALVE
SAMPLE
OUTLET
FLOW
DETECTOR
BYPASS
PURGE
LINE
PRESSURE
GAUGE
IN-LINE TRAP
THERMOCOUPLE
EIGHT PORT SAMPLE
SWITCHING VALVE
GAS
CHROMATOGRAPH

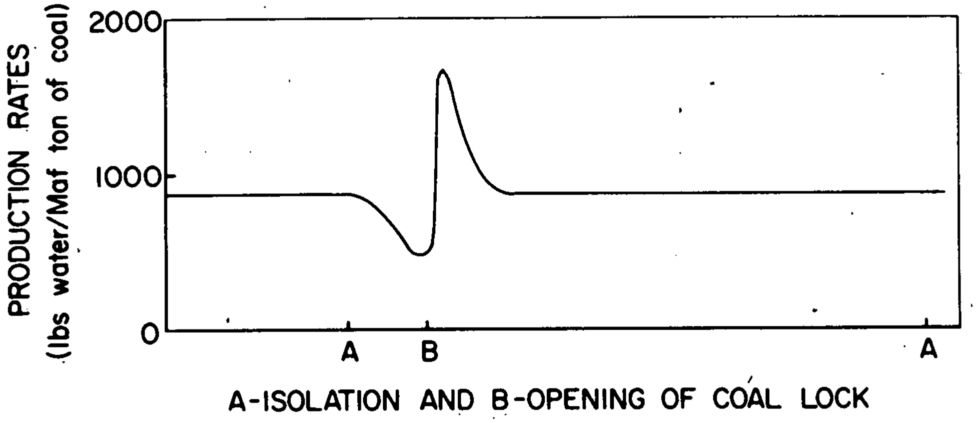

PRODUCT GAS
(100-400 PSIG,
APPROX 300 °F)
SHUT-OFF
VALVE
FULL
PRESSURE
CYCLONE
(100-400 PSIG,
APPROX 300 °F)
PRESSURE
REDUCTION
FLOW CONTROL
VALVE
LOW
PRESSURE
CYCLONE
(APPROX
18 PSIG + 200 °F)
COOLING
WATER
EXIT
COOLING
WATER
INLET
(60 °F)
FIRST STAGE
CONDENSER
COOLING
SOLUTION
EXIT
COOLING
SOLUTION
INLET
(32 °F)
SECOND
STAGE
CONDENSER
CRYOGENIC
TRAP
FILTER
FLOW
MEASUREMENT
POSITIVE
DISPLACEMENT
METER
VENT
(APPROX
2 PSIG + 75 °F)

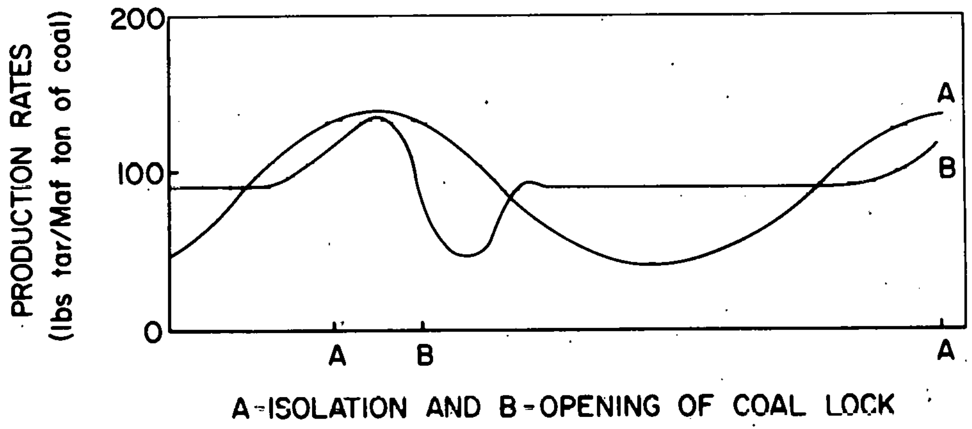

SAMPLE
SAMPLE SWITCHING VALVE
PID DETECTOR
ELECTROMETER
COMPUTING INTEGRATOR
RECORDER
OUTPUT IN AREA AND PERCENT CONCENTRATION

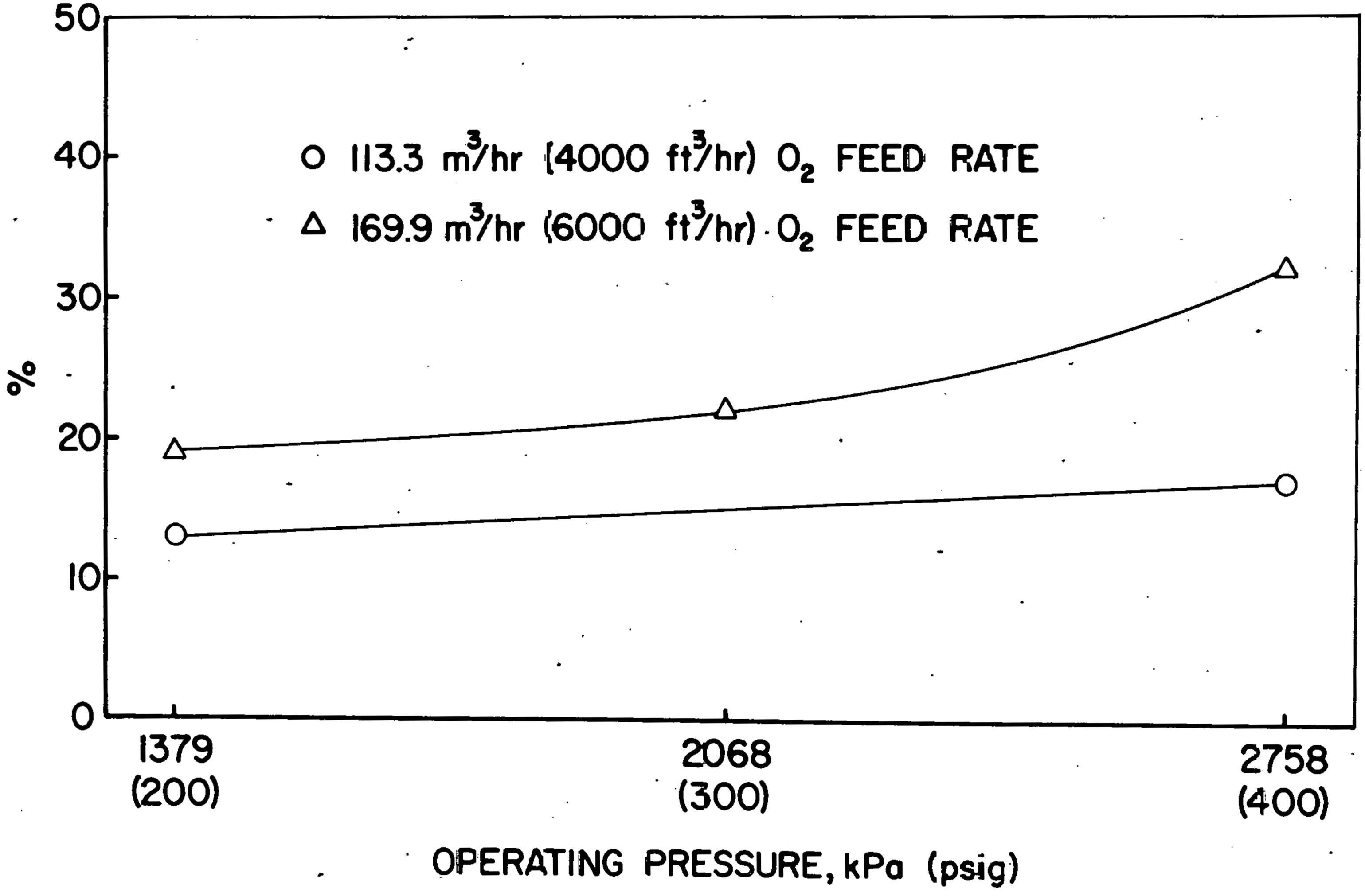


PEAK No.	TEMP RANGE (°C)
1	- 82
2	83 - 115
3	116 - 146
4	147 - 195
5	196 - 226
6	227 -


°C
412
190
0
A
B
A
A-ISOLATION AND B-OPENING OF COAL LOCK


PRODUCTION RATES
(lbs water/Maf ton of coal)
2000
1000
0
A
B
A
A-ISOLATION AND B-OPENING OF COAL LOCK


PRODUCTION RATES
(lbs tar/Maf ton of coal)
200
100
0
A
B
A
B
A
A-ISOLATION AND B-OPENING OF COAL LOCK



○ 113.3 m³/hr (4000 ft³/hr) O₂ FEED RATE
△ 169.9 m³/hr (6000 ft³/hr) O₂ FEED RATE
%
0
10
20
30
40
50
1379 (200)
2068 (300)
2758 (400)
OPERATING PRESSURE, kPa (psig)

LIST OF FIGURES TO BE USED IN PAPER:

"Correlating Process Parameters and Tar/Water Production for a Slagging Fixed-Bed Gasifier"

by

G. G. Mayer, D. R. Hajicek, and P. G. Freeman
Grand Forks Energy Technology Center

Figure 1. - Process flow diagram for the GFETC slagging gasification pilot plant. Configuration used until September 1978.

Figure 2. - Schematic of side stream sampler.

Figure 3. - Schematic of sampling system for on-line gas chromatograph.

Figure 4. - Schematic of gas chromatographic system.

Figure 5. - Typical chromatogram from on-line gas chromatograph.

Figure 6. - Typical temperature profile.

Figure 7. - Typical water production.

Figure 8. - Typical tar production.

Figure 9. - Percent of data period at steady state versus pressure.

IMPROVED BOILER HOUSE OPERATION FROM CO MEASUREMENT AND DIRECT DIGITAL CONTROL

By
George I. Doering
Government Programs Coordinator

Measurex Corporation
One Results Way
Cupertino, California 95014

ABSTRACT

Industrial boiler houses have historically used a measurement of excess oxygen and either pneumatic or electronic analog controls to maintain proper combustion. Observations at numerous such facilities reveal combustion being controlled for natural gas between 15% and 55% excess air (with other fuels somewhat higher), and infrequent use of automatic feedback control.

Motivated by the economic pressure of escalating fuel costs, the Measurex Corporation began working with the Pulp and Paper Industry in 1974 to create an entirely new approach for the control of industrial power houses. The most important product which has evolved from this effort is the 2001 digital computer control system which utilizes a new multi-channel flue gas analyzer for control. The analyzer measures in situ the values of CO, CO_2, SO_2, NO and Opacity, with remarkable accuracy.

The control system employs a Direct Digital Control (DDC) approach supplemented by several optimizing supervisory control loops. The results being achieved with this dramatic new control approach at several sites will be presented.

At one such location, the University of California at Berkeley, there are four boilers with capacity of 100,000 pounds of steam per hour burning natural gas with oil backup. Number one boiler has both FD and ID fans while the other boilers are positive pressure boilers. Steam turbines drive these fans.

The CO measurement is controlling these boilers with relative ease at 3% excess air, reducing fuel consumption over 2%. Controlling both turbine speed and damper position further reduces the fuel requirement by approximately 2%. Drum level is maintained at ±3/8 inches. Additional savings come from monitoring the efficiency of all boilers and allocating loads to the most cost effective units.

Observing the fuel savings and other benefits from controlling with CO measurement and DDC control makes it seem safe to predict that the future will see these become the standard techniques for control of fossil fuel combustion.

IMPROVED BOILER HOUSE OPERATION FROM CO MEASUREMENT AND DIRECT DIGITAL CONTROL

George I. Doering
Government Programs Coordinator

Measurex Corporation
One Results Way
Cupertino, California 95014

INTRODUCTION

The historic low cost of fossil fuel has limited incentive to apply state-of-the-art measurement and control for the combustion of these materials. The author has visited many industrial boiler houses in recent years where natural gas is being fired at 15% to 55% excess air (with other fuels at higher levels). Most large boiler house operations are controlled manually from a measurement of excess oxygen in the flue gas -- very seldom is the signal used for feedback control.

When conducting detailed surveys of boiler houses, O_2 analyzers are often observed to read 3% to 4%, when the actual O_2 values were found to be anywhere from 0 to 8% O_2. The flue gas was found to contain 15,000 PPM CO in one such case. Actual O_2 values should be confirmed by measurement of CO_2.

The controls found in many boiler houses are equally inadequate. Pneumatic control is the rule, but often obsolete, non-standard operating ranges such as 0-30 PSI are still in use. This situation results in inefficient combustion, sluggish controls and low average load utilization. The typical industrial boiler house, long starved for capital investment, is ripe for operational improvement with improved measurement and control.

AN IMPROVED COMBUSTION SENSOR

The Measurex Corporation of Cupertino, California, began applying computer control to boilers in the Paper Industry during 1974. Initially, these systems were used to control the touchy black liquor recovery boiler application. The need was soon apparent for an accurate combustion analyzer. In our historic process control applications the process variable is usually controlled to $\pm 1\%$, therefore the current excess air variation hardly seems a commendable performance.

Our initial efforts to develop a more accurate analyzer led to the purchase and installation of three of the better commercial O_2 analyzers at one location. The purchased probes were not satisfactory on this recovery boiler so a new type probe was designed which gave uninterrupted performance. Still the achieved accuracy was not satisfactory. At times the three units would differ in readings by 3 or 4%. A contributing factor was determined to be flue gas stratification. Exxon Research has carried out studies for the EPA which document this characteristic flow pattern of flue gases.

As a result of this experience, Measurex sensor design engineers began investigating other possibilities and finally selected the measurement of carbon monoxide as having the highest likelihood of success. This use of CO is not new in principle, for control of combustion, but had suffered in execution. Most often CO was measured via the sample extraction technique. Sample handling of parts per million (PPM) gases is always a tedious and difficult task.

At this time Measurex was approached by a small Los Angeles firm that was producing an in situ sensor chiefly used in the electric utility industry for emission monitoring. Their technology was a spin-off from the Jet Propulsion Laboratories in Pasadena which used visible, infrared and ultraviolet electromagnetic frequencies to measure Opacity, CO, CO_2, NO and SO_2. Measurex purchased the technical know-how and manufacturing rights for this unit and began an elaborate test and redesign program.

There were a number of reliability and accuracy problems which needed to be solved, as well as the job of converting the unit from an analog to a digital design. The ability to control the sensor temperature was added. A second key addition was the zero standardization feature, which when combined with permanent internal gas cell and opacity standards, permitted highly accurate automatic standardization of all measurement channels. See Figure I. An accurate zero standardization is impossible without the ability to simulate the boiler being shut down.

COMPARISON OF CO AND O_2 MEASUREMENT

Now that a highly accurate and reliable CO measurement is available, how does it compare with the older industry measurement standard -- excess O_2?

1. CO is directly related to the control variable as an intermediate combustion product -- it is specific to incomplete combustion. O_2 is related to the variable of interest, which is excess air, however in certain cases such as in steel mills and petroleum refineries, the variable composition of the fuel materially degrades the utility of the O_2 measurement

2. Balanced draft boilers and many combustion processes suck in air. O_2 analyzers cannot differentiate between this air and that left over from the combustion process. This problem becomes most severe when one tries to run close to a stoichiometric condition. This type of leakage has little effect on the Measurex sensor since there is no CO in the atmosphere.

3. Beaming the radiations across the flue gas duct or stack provides an averaging of gas stratification. This provides a much more accurate signal which is representative of the total combustion process, a feat not possible from any single point measurement.

4. The CO measurement is an order of magnitude more sensitive than an O_2 measurement. On one boiler Measurex is controlling which burns natural gas, the combustion target is set at 250 PPM CO which is equivalent to 0.48% O_2 or approximately 2.5% excess air. At 350 PPM CO the O_2 value drops 0.1% to .38% and at 150 PPM CO the O_2 increases 0.2% to 0.67%. In this case the CO measurement is 10 to 20 times more accurate than an O_2 signal.

5. A very convenient characteristic of CO measurement is that a common target can be used regardless of the fuel or boiler load. In the case of O_2 the target must be changed with load or fuel mix. This leads to control complexity (which is a problem with analog systems) and necessitates a safety factor which is wasteful of fuel.

Any thoughtful consideration of the above points certainly leads to the conclusion that this analyzer is a genuine state-of-the-art advance in combustion control. The availability of accurate opacity, SO_2 or NO signals can often enhance the control of combustion or emissions.

DDC CONTROL APPLIED TO BOILERS

A comparison of digital computer control vs. analog control is hardly needed by anyone working in the instrumentation or control fields, so only a few points will be made to specifically illustrate key control advances. The inherent capabilities of DDC control can substantially enhance the operation of a boiler house. This is partly true due to the strong interactions that exist between feedwater flow, fuel flow and total air flow. The computer can precisely account for changes in any variable, using extensive feedforward action to minimize upsets. This means that higher control gains can be used to provide quickly responding tight control of all variables.

1. It is unlikely that a standard analog controller could successfully cope with the CO signal mentioned above. The curve is very steep in the control range and the angle of slope changes greatly over a limited range of excess air. See Figure II. The CO loop is a higher level supervisory loop which sets the air to fuel ratio. Measurex uses 13 adaptive gain factors to match the curve's characteristic. There is also considerable logic employed to handle the lead/lag control of air/fuel ratio with load and to limit changes to the air ratio target when load changes. All of this becomes more critical when running close to the stoichiometric level. See Figure III.

2. DDC control can control boilers precisely even under sudden large upset conditions. A case in point is the five element control of steaming drum level. See Figures IV and V. A calculation of mass balance about the drum is augmented by feedforward signals from the fuel flow and drum pressure to compensate for the shrink/swell effect. This improved performance can allow wider operating ranges for the boilers and occasionally permit operation with one less boiler on line than would otherwise be practical.

3. Fan power can be reduced as excess air drops. There are cases where improved control can substantially cut fan power. For instance, when a fan is driven by a steam turbine the addition of a mid-range control algorithm will open the damper and reduce the fan speed, thus saving power. See Figure VI. This control must be precise and handle the interactions between fan speed and damper position. The relationships are quite non-linear.

4. Two other tasks uniquely handled by digital logic are the proportioning of fuels in a multi-fuel boiler and the optimum allocation of loads to a group of boilers. The objective with multiple fuels is to burn as high a percentage as possible of the cheaper fuel. This may be limited by a variety of factors, such as emissions, fuel feeding capability and combustion stability.

   Allocation of loads in boiler houses has usually meant an even split or the base loading of certain units. Either of these approaches ignores the money-making potential of allocation by incremental cost. The Measurex algorithm continually determines what it will cost for each boiler to produce an incremental amount of steam. Loads are then apportioned among the boilers while accounting for boiler operating constraints to operate the boiler house at the minimum possible fuel cost.

SUMMARY

Systems employing these new technologies are at work in Europe, Japan, and North America, controlling the combustion of black liquor, hog fuel, natural gas, oil and coal. The application of these technologies will produce various degrees of fuel savings, depending on a number of factors. Improved combustion efficiency can save from 1% to 4% of the fuel depending on stack temperatures, excess air levels and fuel type. See Figure VII. Fan power is usually reduced 0.5% to 1.0% of boiler fuel use, depending on type of fan and driver and the amount of excess air reduction possible.

The optimum allocation of loads will save anywhere from nothing to over 5% of the fuel cost depending on the number of boilers, efficiency characteristics of the boilers and the cost and types of fuels being burned. The more complex the situation, the greater the possible savings.

A boiler house survey can lead to reasonably precise estimates of the potential fuel savings from the introduction of CO measurement and DDC control.

While the present installations are controlling only on a variety of industrial boilers, application of similar technology would seem suitable for electric utility boilers, various oven and kiln processes where combustion occurs. The sensor with its ability to measure opacity, SO_2 and NO should also play an important role for control of fluidized bed boilers or those burning municipal waste or biomass.

Working with these new combustion control systems and observing the improved performance achieved on a variety of industrial boilers, one feels very comfortable in predicting a very large future role for CO measurement and digital control of fossil fuel combustion processes.

REFERENCES

1. The Industrial Powerhouse of the Future by Thomas T. Dingo, Energy Management and Plant Engineering, General Motors Corporation. Presented at Industrial Coal Conference, University of Kentucky, May 2, 1979.

2. Control of Excess Air in Waste Heat Boilers by J. W. Womack, Mobile Research and Development Corporation. AICHE, 1975.

3. The Case For Continuous Monitoring by Dr. P. C. Wolf, Ethyl Corporation. Power, August 1974.

4. Determination of the Magnitude of SO_2, NO, CO_2, and O_2 Stratification in the Ducting of Fossil Fuel Fired Power Plants by M. W. Gregory, A. R. Crawford, E. H. Manny and W. Bartok, Exxon Research and Engineering Company. APCA, June 1976.

5. Field Tests of Industrial Stoker Fired Boilers for Emission Control by J. E. Gabrielson and P. L. Langsjoen of KVB, Inc. Proceedings of the Third Stationary Source Combustion Symposium, Vol. I, EPA Interagency Energy/Environment R & D Program Report, San Francisco, February 1979.

6. Fuel Cost Savings Through Computer Control of a Boiler Complex - Two Case Histories by C. M. Worthley, Measurex Corporation. International Energy Conference, Houston, Texas, April 1979.

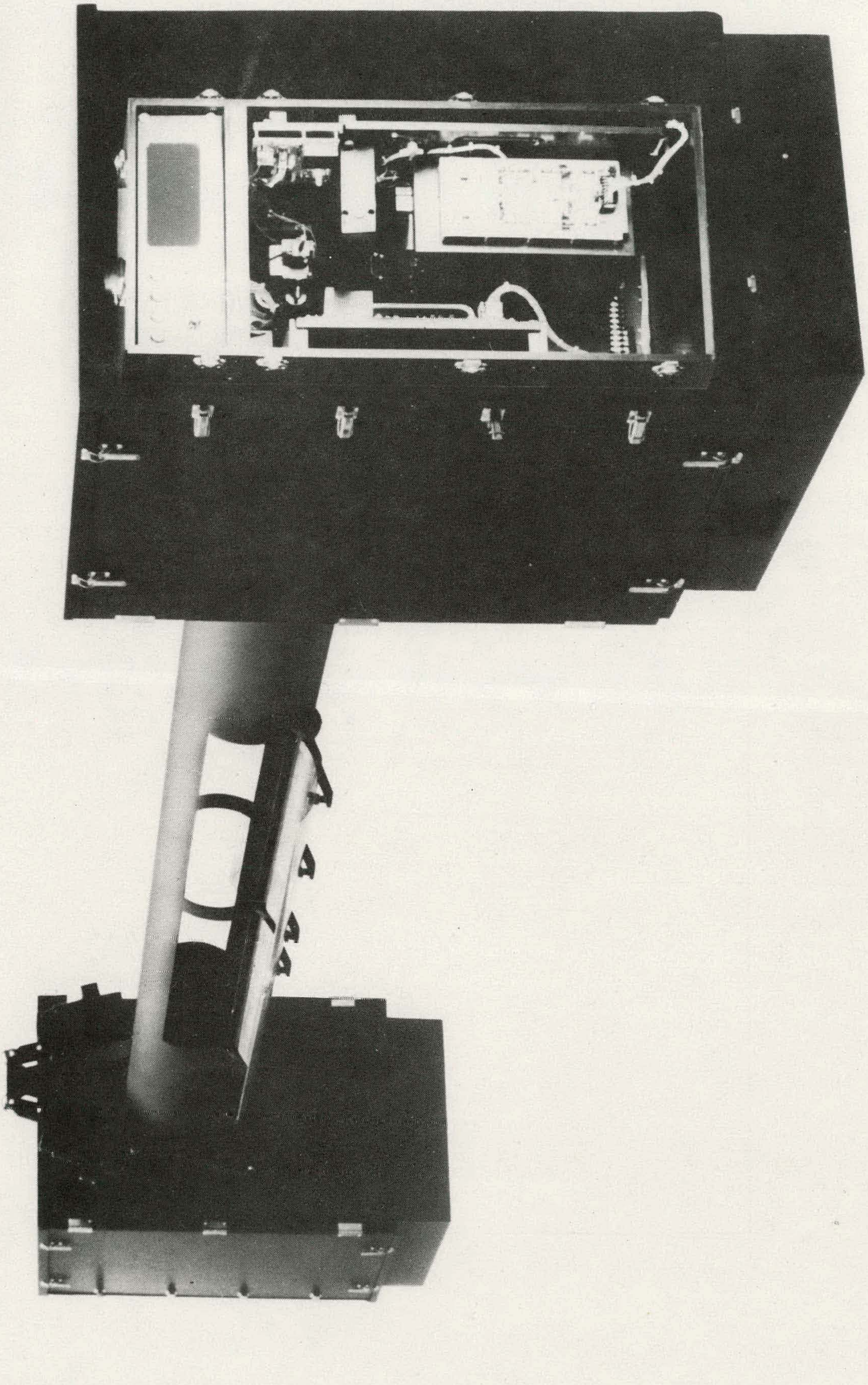


Figure I

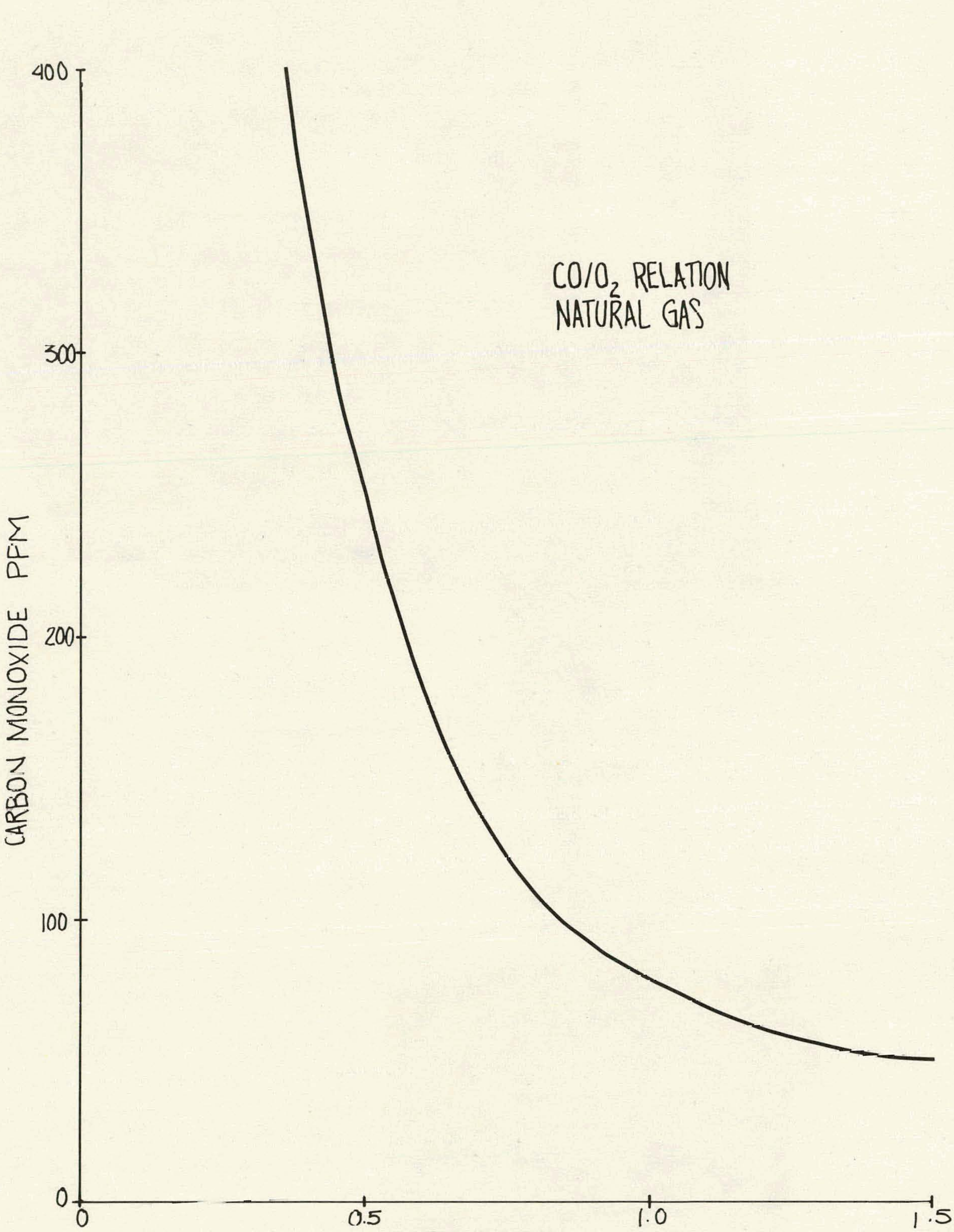

CO/O$_2$ RELATION
NATURAL GAS
CARBON MONOXIDE PPM
400
300
200
100
0
0
0.5
1.0
1.5
EXCESS OXYGEN

Figure II

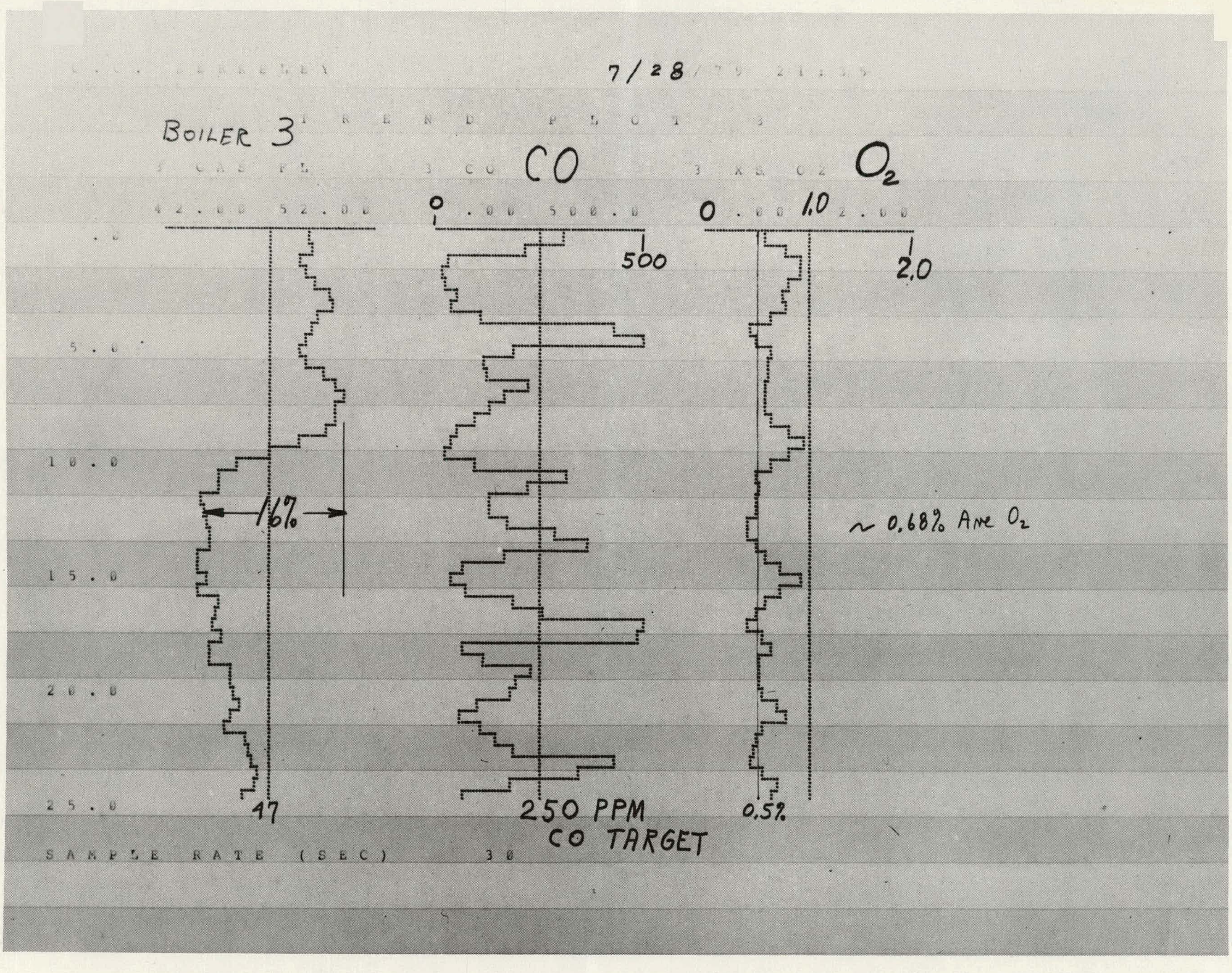

U.C. BERKELEY 7/28/79 21:35
TREND PLOT 3
BOILER 3
3 GAS FL
3 CO
CO
3 XS O2
O2
42.00 52.00
0 .00 500.0
0 .00 1.0 2.00
500
2.0
.0
5.0
10.0
15.0
20.0
25.0
16%
~ 0.68% Ave O2
47
250 PPM
CO TARGET
0.5%
SAMPLE RATE (SEC) 30

Figure III

DRUM LEVEL CONTROL

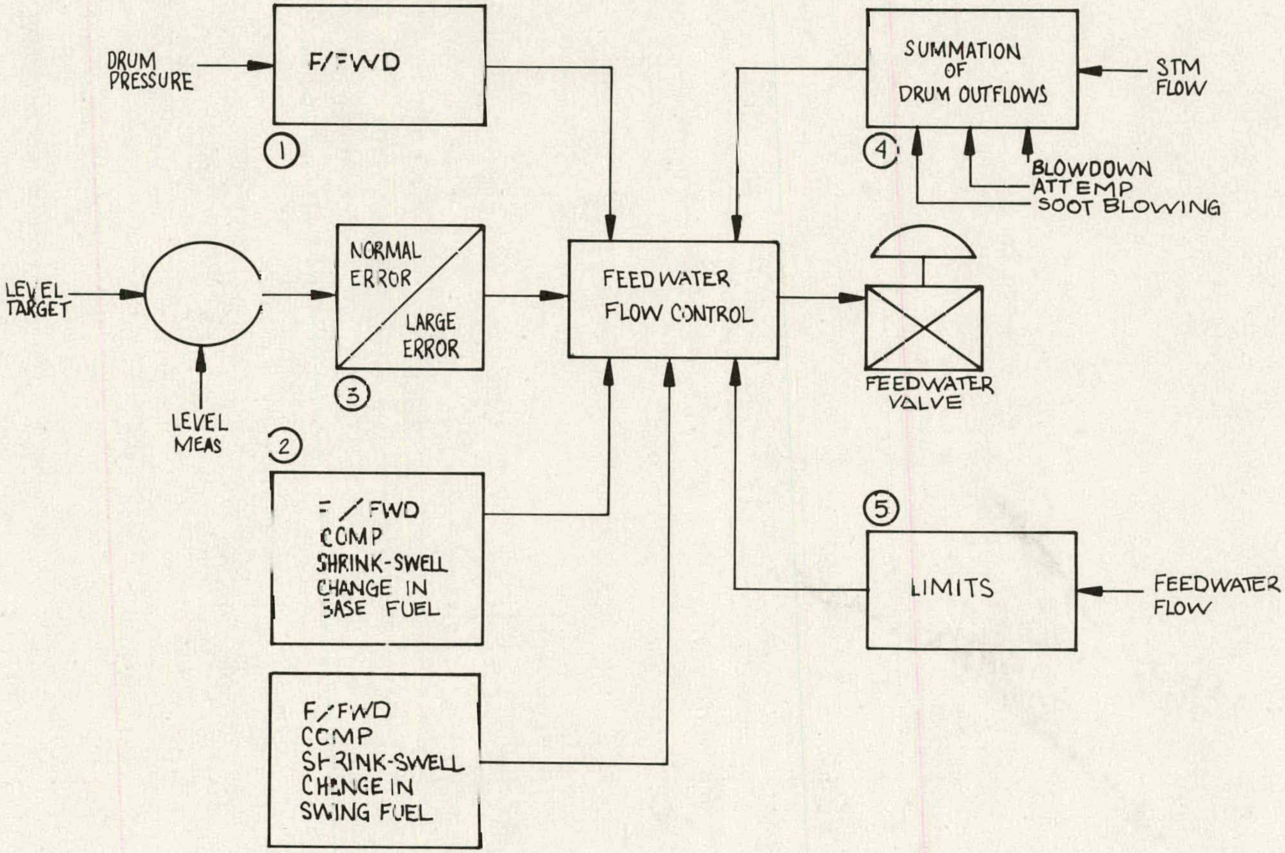


Figure IV

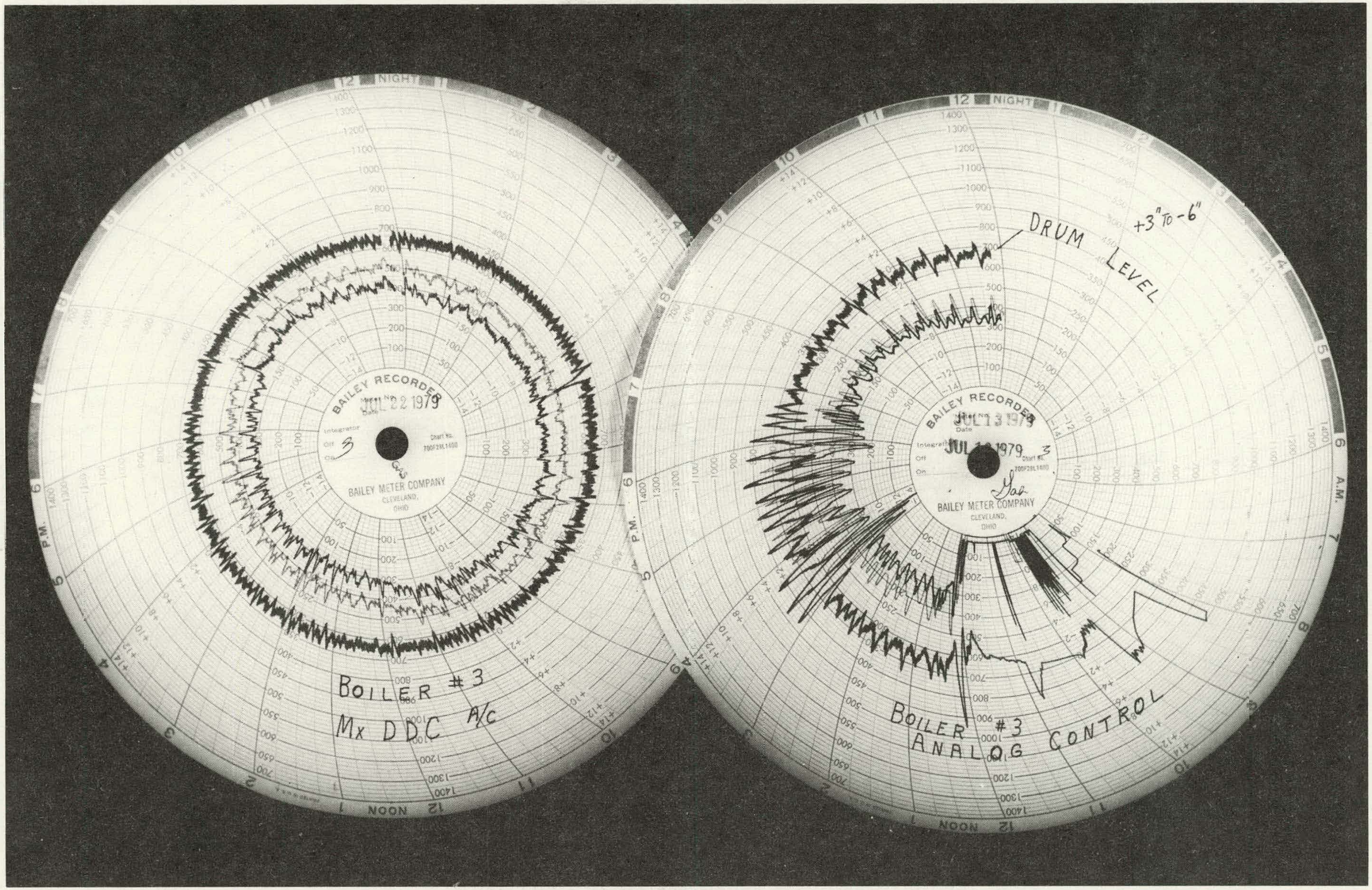

BAILEY RECORDER
JUL 22 1979
3
Gas
BAILEY METER COMPANY
CLEVELAND, OHIO
BOILER #3
Mx DDC A/C
DRUM LEVEL
+3" TO -6"
BAILEY RECORDER
JUL 13 1979
3
Gas
BAILEY METER COMPANY
CLEVELAND, OHIO
BOILER #3
ANALOG CONTROL
12 NIGHT
NOON
P.M.
A.M.

Figure V

FURNACE DRAFT MID-RANGE CONTROL

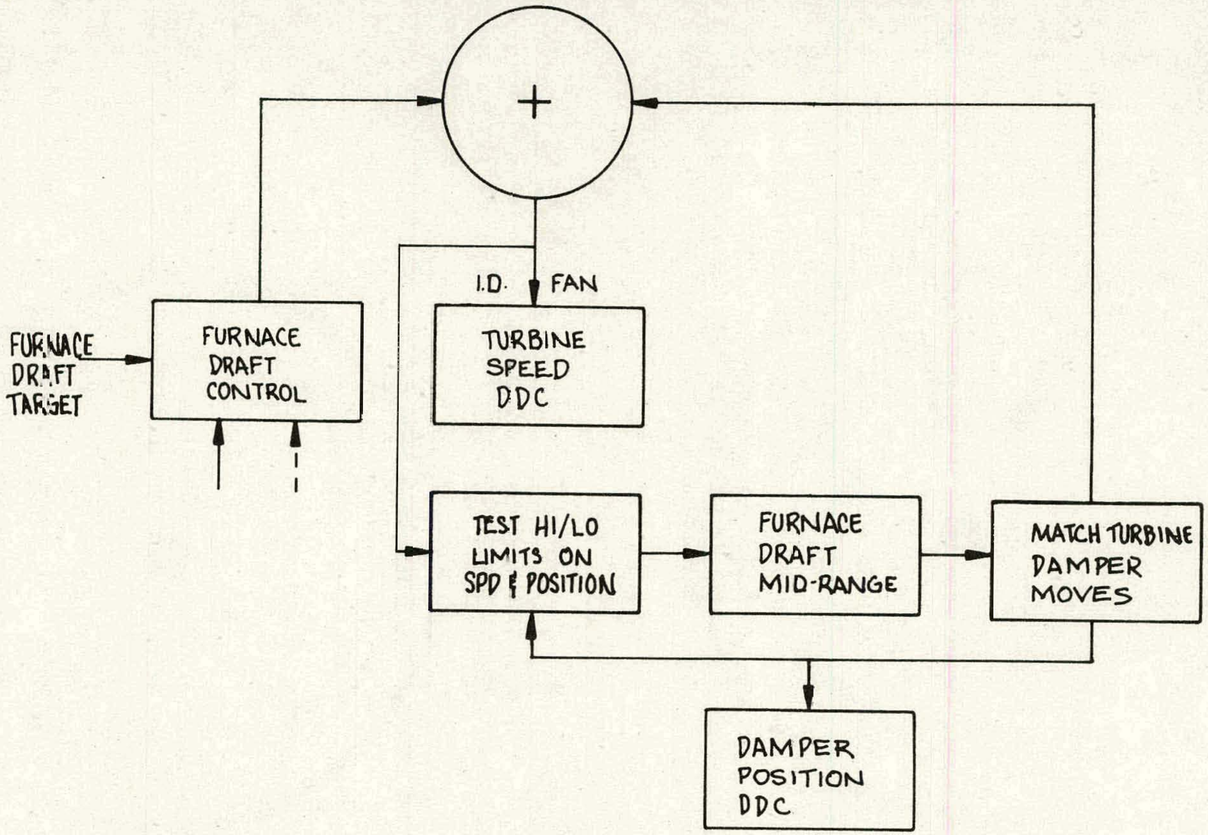


Figure VI

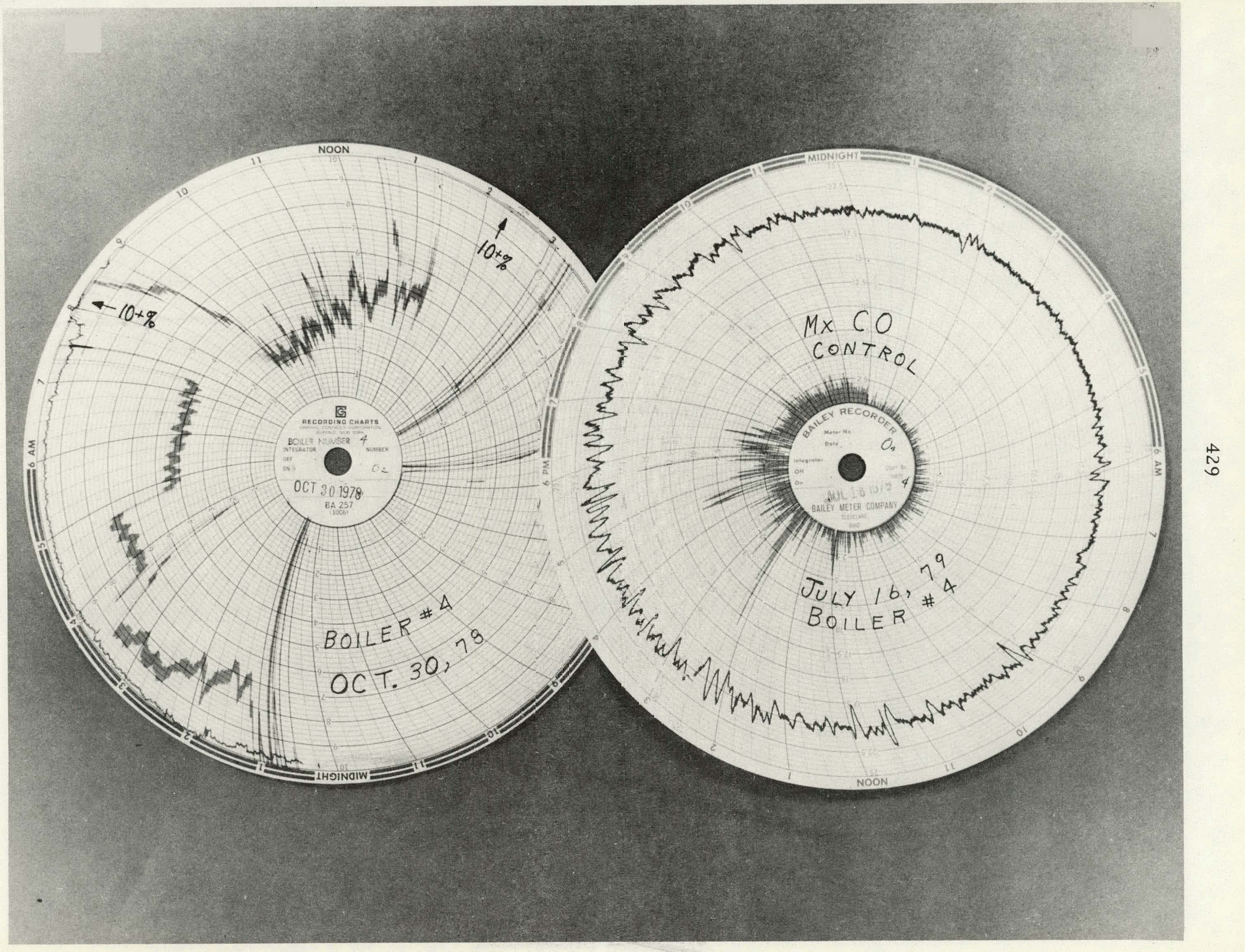

NOON
MIDNIGHT
6 AM
6 PM
10+%
10+%
RECORDING CHARTS
BOILER NUMBER 4
O2
OCT 30 1978
BA 257
BOILER #4
OCT. 30, 78
MIDNIGHT
NOON
6 AM
Mx CO
CONTROL
BAILEY RECORDER
O2
JUL 16 1979 4
BAILEY METER COMPANY
JULY 16, 79
BOILER #4

Figure VII

DETERMINATION OF S_2 IN REACTIVE GAS MIXTURES BY TUNABLE ATOMIC LINE MOLECULAR SPECTROSCOPY

Tetsuo Hadeishi, Alan V. Levy, David P. Whittle, and Enrique Cuellar*

Lawrence Berkeley Laboratory
Berkeley, California 94720

Presented at the 1979 Symposium on Instrumentation and Control for Fossil Energy Processes

Denver, Colorado
Aug. 20-22, 1979

*Presenting author

Lawrence Berkeley Laboratory

University of California
Berkeley, California 94720
Telephone 415/486-4000
FTS: 451-4000

Bldg. 70-143

August 29, 1979

Richard W. Doering
Applied Physics Division
Building 316
Argonne National Laboratory
9700 S. Cass Ave.
Argonne, Ill. 60439

Dear Dr. Doering:

I realized that the original copy of the paper I presented at the recent Symposium in Denver and which I gave to you is not ideally suited for reproduction, as the type is light and runs too close together. I have had the paper retyped on standard ANL forms and I am sending it to you. This retyped version of the paper is identical to the one you have. If you are able to use this retyped form of the paper you will need to add to it the three 8 1/2 x 11 photographs of the figures which accompany the paper I gave you in Denver.

It is not too important if the switch in the papers cannot be carried out, as this retyped version serves only an aesthetic purpose. Also, it is not necessary for you to send back to me whichever copy is not used for the Symposium Proceedings.

I apologize to you for this inconvenience.

Sincerely,

Enrique Cuellar

Enrique Cuellar

DETERMINATION OF S_2 IN REACTIVE GAS MIXTURES BY TUNABLE ATOMIC LINE MOLECULAR SPECTROSCOPY

Tetsuo Hadeishi, Alan V. Levy, David P. Whittle, and Enrique Cuellar*

Lawrence Berkeley Laboratory
Berkeley, California 94720

I. INTRODUCTION

In the search for energy supplies, the United States is projected to rely heavily on coal, which is the most abundant fossil fuel available. Several methods for extracting energy from coal are currently being explored; the final choices of energy conversion processes will doubtlessly balance economic as well as environmental considerations. The presence of sulfur in coal is of clear importance, as this corrosive species affects not only the design and efficiency of an energy conversion plant, but also represents a potential pollutant which must be controlled if coal is to be used in an environmentally acceptable manner.

With this in mind, we have initiated a research effort to develop a real time sulfur probe to determine quantitatively the presence of S_2 in an energy conversion process such as coal gasification. Traditionally, the optical detection of molecules has been accomplished by infrared absorption spectroscopy using either thermal light sources or infrared lasers. In general, because of the difference in the oscillator strengths for transitions, a measurement that depends on an electronic transition of a molecule in the ultraviolet (UV) region of the spectrum is more sensitive than one that depends on a vibrational or rotational transition in the infrared (IR) or far infrared (FIR) spectral regions. Furthermore, the sensitivity of photodetectors is also better in the UV than in the IR region. However, the spectrum due to electronic transitions is much more complicated and considerably less selective than vibrational-rotational IR or rotational FIR transitions. In the vast majority of cases, the rotational structure can be resolved in the IR and FIR spectrum, but not in the UV spectrum, except for the case of small molecules[1]. Even for small molecules, high resolution

---

* presenting author

($\sim$50,000) is required for the observation of rotational structure. Since the sharp structure that is necessary for high specificity is difficult to observe, UV spectroscopy has not been used as often as IR spectroscopy for the analysis of trace molecules present in a gas mixture.

Recently, we have developed a new technique for the determination of S_2 by utilizing UV absorption of a magnetically tuned and frequency modulated atomic line source[2,3]. This method allows for high resolution spectra to be obtained without the need of a high resolution spectrograph. Hadeishi and Shimomura[4] found that a Cr atomic emission line at 3017.6 Å can be tuned to a vibronic transition of S_2 by the Zeeman effect. In this technique, one of the Zeeman components of the emission line is exactly tuned to coincide with a single vibrational rotational transition in the $^3\Sigma$ - $^3\Sigma$ electronic manifold of S_2, while the other components are shifted away from the S_2 line. The matched component indicates the extent of S_2 plus background absorption, while the unmatched components indicate background absorption only. By means of differential measurements of the intensities of the matched and unmatched Zeeman components, a perfect background correction can be acheived. In addition to being highly specific, this technique is capable of high sensitivity because the oscillator strength of electronic transitions in the vacuum UV, UV, and visible regions of the spectrum are much larger than those for transitions in the IR. Furthermore, by using an exactly tuned very narrow (a few GHz half width) atomic line source, the high sensitivity predicted by the true absorption coefficient can be obtained.

In the vast majority of cases this technique does not suffer from interference due to absorption of light scattering caused by coexisting large molecules and particulates (smoke or soot) present in the absorption region. Because the absorptions due to electronic transitions of polyatomic molecules are almost always constant over a spectral region of a few GHz, there is no difference in absorption between the two Zeeman components.

II. EXPERIMENTAL DESIGN

A block diagram of the experimental system is shown in Figure 1. Figure 2 shows the construction of the light source. The light source is a modification of a magnetically confined arc lamp described by Hadeishi and

Anderson[5]. The lamp chamber is made of stainless steel and is placed between the poles of a permanent magnet. The gap between the poles is reduced by welding poles made of iron to the discharge chamber in order to obtain the required field strength. Argon flows through the light source at a pressure of 2-10 torr. The cathode is made of stainless steel on which a nickel-chrome sheet metal strip is spot welded. The anode is constructed from an automobile spark plug modified to minimize the likelyhood of discharge to the chamber wall. D.C. power is supplied to the light source at a current between 30 and 100mA. Discharge to the cathode results in intense Cr atomic emission at 3017.6 Å. In the presence of the magnetic field the atomic emission is split into its Zeeman components. One of the Zeeman components exactly matches a rotational transition in the v'=7 - v"=2 vibrational band of the $^3\Sigma$ - $^3\Sigma$ electronic transition manifold of S_2[6].

The variable phase retardation plate[7] shown in Figure 1 consists of a block of fused quartz that is mounted on a magnetic clamp. The applied stress causes an optoelastic effect which produces a retardation of the phase of the light. The variable phase retardation plate is used to switch the Zeeman component matched to the S_2 absorption and the unmatched Zeeman component alternately.

III. RESULTS AND DISCUSSION

A mixture of H_2S in H_2 gas (7.5% H_2S, Matheson Gas Co.) was heated in a 10 cm long tubular quartz cell under flowing conditions, and the resulting S_2 molecules were continuously detected by this new method. S_2 is formed in the decomposition of H_2S by the reaction

$$H_2S \rightleftharpoons H_2 + 1/2\ S_2 \quad \Delta H = 20.3\ \text{kcal/mole}$$

Figure 3 shows the signal due to S_2 recorded on a strip chart recorder. The H_2S flow rate is 0.024 ℓ/min. The S_2 signal increases slowly as the wall temperature of the quartz cell increases to about 750 °C. The gas temperature under flow conditions, however, is considerably lower, and it is this temperature that determines the extent of dissociation of S_2. If the flow of H_2S is cut off, the intensity of the signal due to S_2 increases, indicating that the gas temperature rises and S_2 concentration increases.

The calibration of the detection system was established from the absolute absorption cross section determined from an S_2 vapor cell similar to that used by Durand[8]. The vapor pressure of sulfur was taken from Ref. 9. In this manner, we estimate the measured S_2 concentration under the flow conditions described above and at a gas temperature of about 350 °C is 8×10^{-4} atm.

IV. CONCLUSIONS

We have demonstrated the possibility of detecting S_2 quantitatively in a reactive gas mixture by the application of molecular spectroscopy using a Zeeman tuned frequency modulated atomic line source. By splitting the Cr atomic emission line at 3017.6 Å and magnetically tuning one component into resonance with a sharp molecular absorption of S_2, it is possible to detect this species on a real time basis. Furthermore, differential absorption measurements allow for a perfect background correction. Therefore, this technique should be very powerful for the <u>in situ</u> analysis of S_2 in samples containing smoke or a mixture of various kinds of gases.

REFERENCES

1. G. Herzberg, "Molecular Spectra and Molecular Structure III. Electronic Spectra and Electronic Structure of Polyatomic Molecules", Van Nostrand Reinhold Co. New York (1966).

2. H. Koizumi, T. Hadeishi, and R.D. McLaughlin, Appl. Phys. Letters 34, 382 (1979).

3. H. Koizumi, T. Hadeishi, and R.D. McLaughlin, Appl. Phys. Letters 34, 277 (1979).

4. T. Hadeishi and S. Shimomura, unpublished result.

5. T. Hadeishi and T. Anderson, Opt. Comm. 23, 252 (1977).

6. A. Fowler and W.M. Vaidya, Proc. Royal Soc. 132 , 310 (1931).

7. B.D. Zak, B. Chang, and T. Hadeishi, Appl. Opt. 14, 1217 (1975); T. Hadeishi, U.S. Patent 3,957,375.

8. E. Durand, J. Chem. Phys. 8, 46 (1940).

9. F. Rosebury, "Handbook of Electron Tube and Vacuum Techniques", Addison-Wesley (1965).

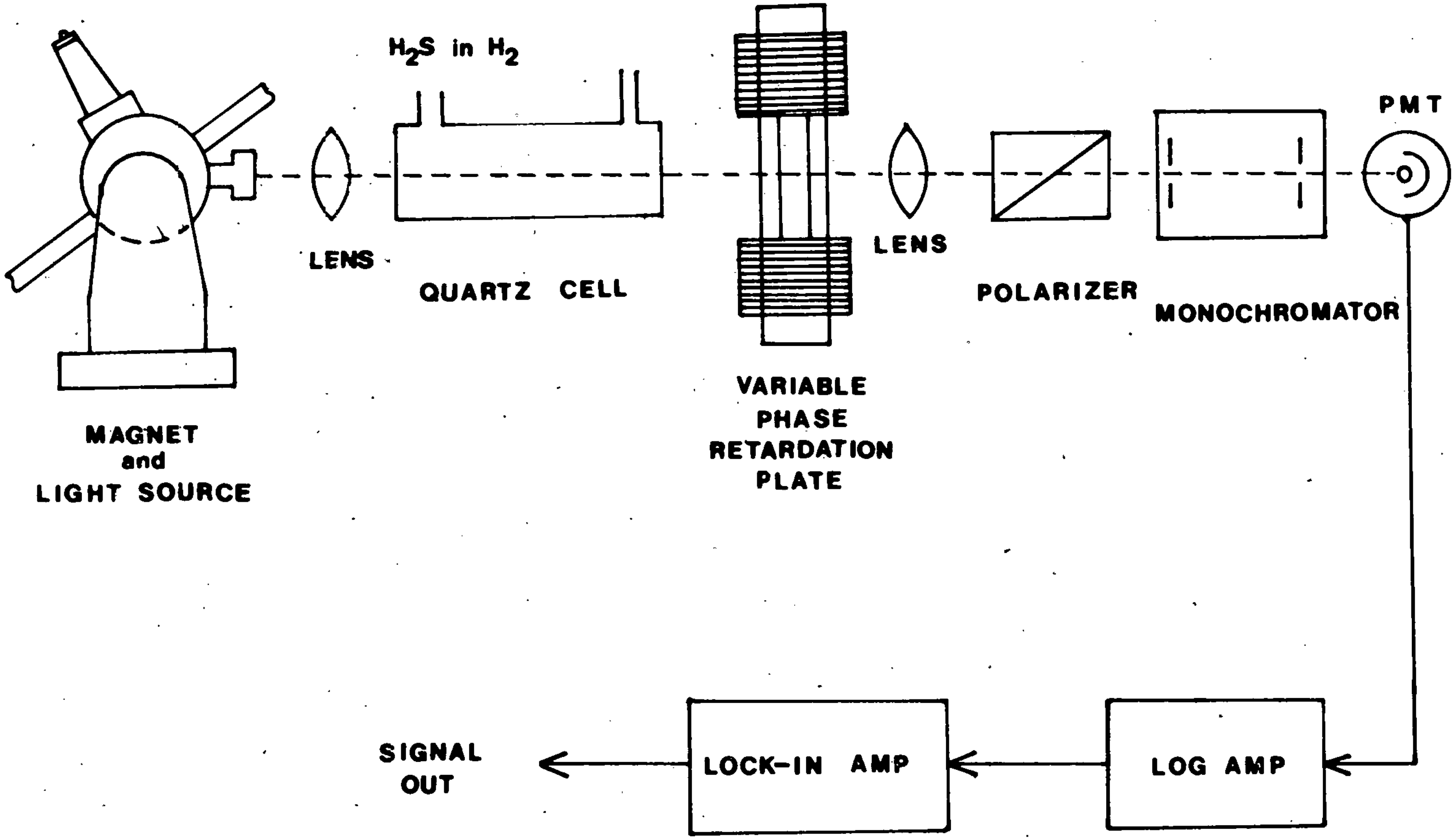


FIGURE 1. BLOCK DIAGRAM OF THE EXPERIMENTAL APPARATUS

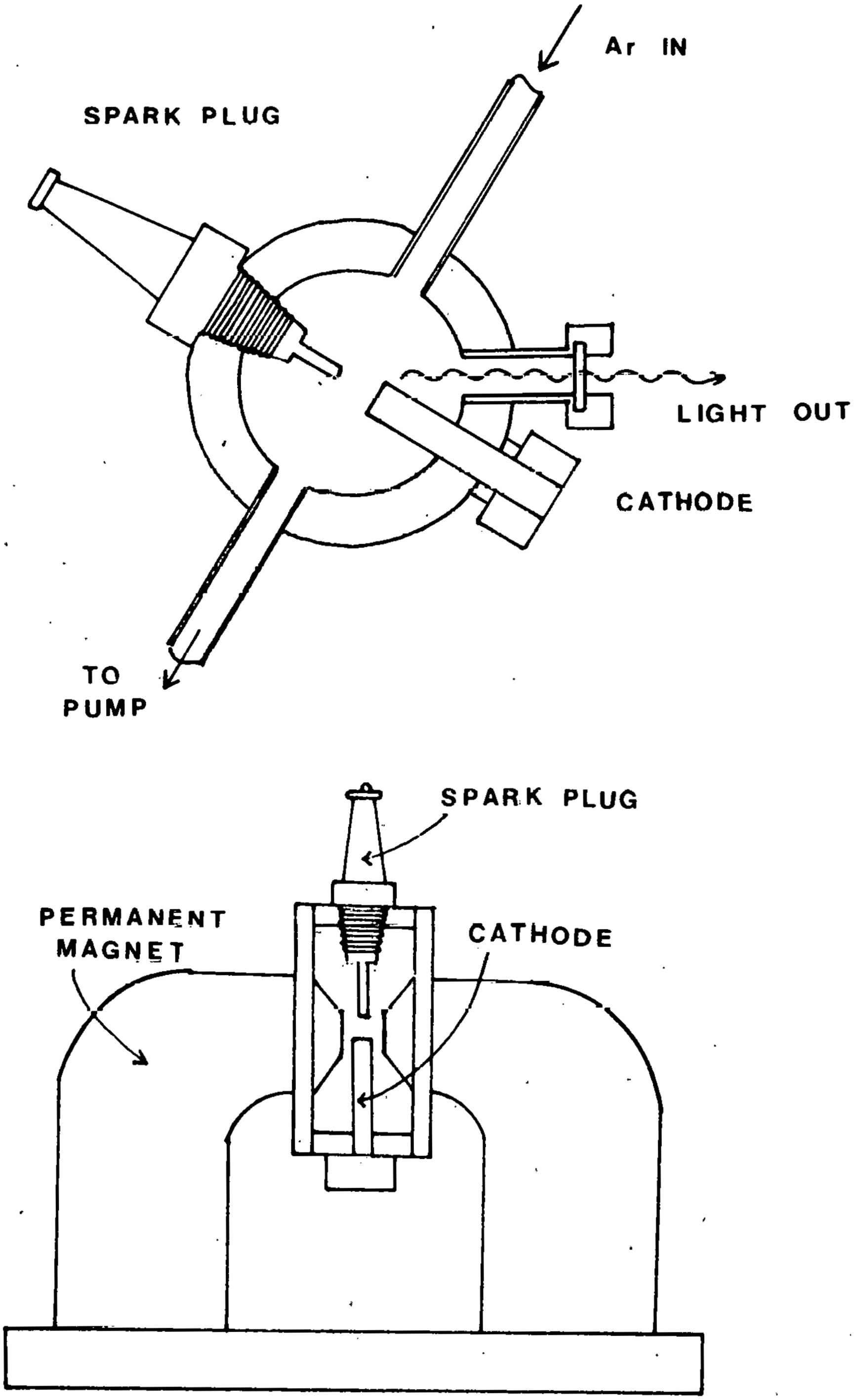


FIGURE 2. MAGNETICALLY CONFINED ARC LAMP

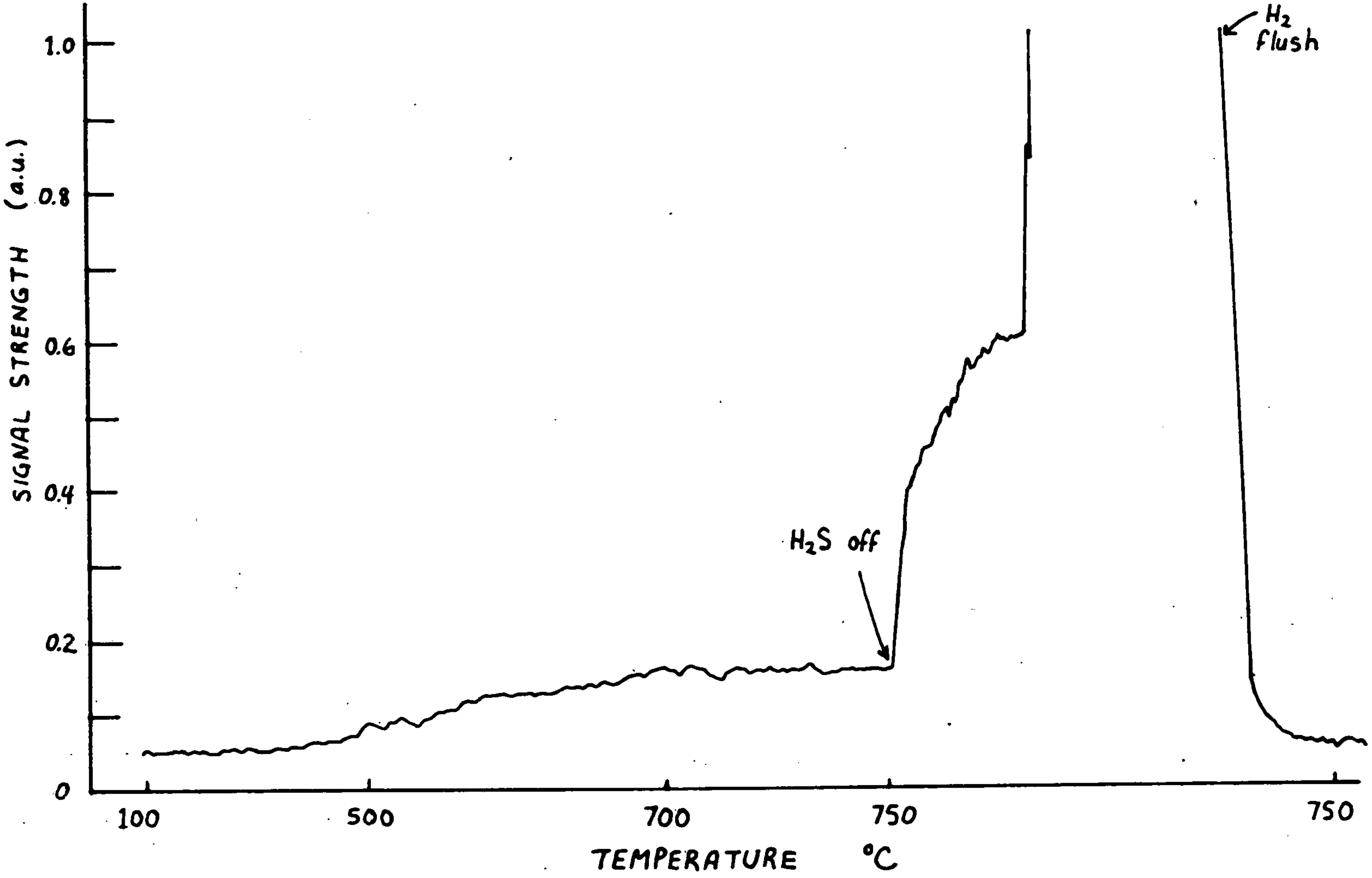


FIGURE 3. S_2 SIGNAL OBTAINED WITH THE PRESENT TECHNIQUE.

ON-LINE NONINTRUSIVE MEASUREMENTS OF FLY ASH AND OTHER COMBUSTION-GENERATED PARTICULATES

William D. Bachalo
Spectron Development Laboratories, Inc.
Costa Mesa, California 92626

ABSTRACT

Particle diagnostic instrumentation that have been developed for application to the measurement of combustion-generated particulates and aerosols are described. The laser light scattering methods used provide a convenient means for evaluating the flue gas cleanup mechanisms and are suitable for use as real time monitors of the particulate loading levels in the system.

Aerosol sizing systems capable of measuring droplet size and velocity in dense sprays have been demonstrated over a broad range of applications including fuel sprays, agricultural sprays and in meteorological enrivonments. These systems are suitable for applications in scrubber collection efficiency evaluation, monitoring water droplet formation in steam plants, and liquid droplet formation in industrial exhaust gas.

Unique observations of burning coal particles obtained with the use of holographic methods are also presented and discussed.

* * * * * *

Wednesday Afteroon, August 22

Temperature, Level and Pressure Instrumentation

BEHAVIOR OF HIGH TEMPERATURE THERMOCOUPLES IN COAL GASIFICATION REACTORS

G. W. Burns and M. G. Scroger
National Bureau of Standards
National Measurement Laboratory
Center for Absolute Physical Quantities
Washington, D. C. 20234

ABSTRACT

Thermocouple assemblies removed from the combustion zone (stage 1) and from the entrained bed section (stage 2) of the Bi-Gas pilot plant gasifier were examined to characterize their structural, chemical, and thermoelectrical behavior. Chromic oxide coated molybdenum thermowells used to protect thermocouples in stage 1, where temperatures range from 1350 to 1650°C, typically survive for only 10 to 100 hours, depending on gasifier operating conditions. The Cr_2O_3 coating was found to be completely eroded away from thermowells operated for 15 hours, and the molybdenum showed substantial corrosion and was weakened structurally due to the formation of a grain boundary phase. Stainless steel thermowells used for about 200 hours in stage 2 of the gasifier, where temperatures range from 750 to 1100°C, exhibited very little corrosion or erosion, but the stainless steel sheathed Type K thermocouples contained in the thermowells were found to have experienced as much as a 2.5% decrease in thermoelectric output due to preferential oxidation of chromium in the positive, nickel-9.5% chromium thermoelements. New prototype thermocouple assemblies designed to alleviate the aforementioned problems were constructed at NBS, and their evaluation in the Bi-Gas gasifier is in progress. The salient features of the prototype assemblies are described.

INTEGRATED RADIOMETRIC SYSTEM FOR GASIFIER TEMPERATURE MEASUREMENTS - PART 2

Frederic M. Zweibaum
Alan T. Kozlowski
William E. Surette, Jr.
Barnes Engineering Company, Stamford, CT. 06904

ABSTRACT

An integrated radiometric system for gasifier temperature measurement has been developed, fabricated and is undergoing tests at the Bituminous Coal Research Bi-Gas Pilot Plant at Homer City, Pennsylvania. The buyer is C.F. Braun & Company for the Energy Research and Development Administration and The American Gas Association.

The purpose of this system is to monitor and to scan the radiation inside a coal gasifier reactor in order to perform several simultaneous functions. These include flame detection for alarm functions and temperature measurement by measuring radiation 2.1 micrometers in wavelength. Another function is monitoring the gasification process by scanning radiation over the range of 1.5-5.5 mictometers. The radiometric system monitors and scans the process by viewing it through a sighting tube.

The installation and its principles of operation were described in the previous symposium on this subject. This paper briefly reviews these concepts and continues with three major descriptions. First is a review of the system and the initial measurements that have been made with it. Second is a review of a modification made to permit gasifier temperature measurements by the two-color ratio method. Third is a description of a method for making these same measurements with a scanning radiometer operating under the control of a built-in microprocessor.

1. REVIEW OF INITIAL INSTALLATION

Optimizing the performance of a coal gasification system requires continuous knowledge of the peak process temperature being achieved together with a knowledge of the nature of the flame processes that are taking place within the reactor. Developments that have been made in industrial radiometry make it possible to accomplish both these goals.

The first installation is shown in Figure 1. In this arrangement, the sensing heads of two radiometric instruments are installed in an explosion-proof container close to the outside of the reactor chamber. Beam splitters inside the container make it possible for both instruments to view the process simultaneously through a sighting tube that penetrates through the reactor wall. Electrical outputs from the sensing heads go through 300 feet of cable to electronic control and readout units located in a remote control room.

Each of the two instruments is designed to accomplish a separate but related task in continuous temperature measurement and spectral scanning. First, there is an instrument that continuously monitors the temperature of the char and combustion products in the lower part of the reactor. This monitor is designed to determine the peak process temperature up to 3200°F. The monitor is supplied with a single set point control to produce a warning signal at maximum safe operating temperature.

Second, there is a spectral scanning instrument whose purpose is to provide the capability of monitoring the process. Under normal operating conditions, the input to the scanning sensor should approximate a blackbody distribution. Discontinuities in the blackbody curve would indicate the presence of other processes, representing reactions of interest for possible investigation.

In initial tests, the system demonstrated successful operation as a temperature monitor and as a spectral scanner. In the spectral scanner mode, the system demonstrated capability in determining the presence, relative concentration and temperature of combustion by-products. Figure 1D is an example of such a spectral scan.

The original concept involved incorporating a second temperature monitor sensing head in the explosion-proof container. Space had been left for this in the container, and the beam splitter system had been designed to permit its installation and simultaneous operation. It was decided to install this second instrument together with a ratio-processor system that makes it possible to use the "two-color" ratio method to be described.

2. RATIO-PROCESSOR FOR TWO-COLOR RATIO MEASUREMENTS

Principles

The Ratio Processor is an addition to the Integrated Radiometric

System for Gasifier Temperature Measurements. Its purpose is to permit that integrated system to make gasifier temperature measurements by the two-color method.

At temperatures below incandescence, the total radiation method is commonly used to make non-contact temperature measurements of a surface area of interest. This method is based upon the fact that the total radiant energy output over a broad spectral region is a well known function and is proportional to the fourth power of the absolute temperature multiplied by the surface emissivity. Although a knowledge of surface emissivity is required, this is well known for an extremely wide number of materials and is sufficiently high to be practically ignored for most opaque insulators.

At temperatures above incandescence, the emissivity of the surface varies with temperature and is not well known. For such conditions, the two-color ratio method can be used. In this method, the energy from the surface of interest is measured in two different narrow spectral regions. When the ratio of these two energy levels is determined, the value of emissivity is cancelled. Thus, the temperature can be determined with accuracy without knowning the emissivity, as long as the emissivities in the spectral regions are approximately equal. See Figure 2 Part A.

The Ratio Processor automates the production of this ratio. It produces direct reading outputs that indicate the ratio and the temperature derived from this ratio. It also produces voltages directly proportional to these outputs as well as other outputs that provide automatic control function. See Figure 2 Part B.

Description of Ratio Processor

The Ratio Processor and its place in the Integrated System for Gasifier Temperature Measurements are shown in Figure 3.

The original Integrated System contained the Model 12-550 Optical Head and Electronic Control Unit, the Model 12-880 Optical Head and Electronic Control Unit identified as "A" together with beamsplitters 1 and 2 plus an explosion-proof container.

The Ratio Processor System consists of the Model 12-880 Optical Head and Electronic Control Unit identified as "B", the Ratio Processor Unit and beamsplitter 3. These components are integrated into the original system as shown in Figures 4 and 5.

Figure 4 shows the three optical heads installed in the explosion proof container. Figure 5 shows an assembly of all the electronic units not yet installed in their racks. At the top is the electronic controller unit for the ratio processor. The large digital readout at the upper left is the temperature as determined by the two-color ratio method of measurement. Immediately below is the digital readout of the ratio between the outputs of Model 12-880 Optical Heads A and B.

The second unit from the top is a single rack mount unit containing the Model 12-880 electronic units. At the bottom is the electronic control unit for the Model 12-550 Research Radiometer. Under the right edge of the large meter is a SCAN-MANUAL toggle switch that selects whether the spectral filter in the Optical Head will scan continuously (SCAN) or be motor "jogged" (MANUAL) to any desired position.

Because of the addition of the second Model 12-880, a number of items of information become newly available. These new items are provided by the upper electronic unit in Figure 5 and are as follows:

A. A direct temperature measurement derived from the ratio of the two Model 12-880 outputs. This ratio is linearized and encoded into a digital presentation directly in °F on a 3-3/4 digit display.

B. A dual set point controller which permits selecting both a high and a low temperature limit for control operation.

C. A 4-20 milliampere output for automatic control purposes. This current is linear with respect to the temperature derived from the ratio.

D. A comprehensive set of front-panel and rear-panel connectors for obtaining electrical signals equivalent to all inputs and outputs concerned in the ratio process.

Figure 6 shows the system undergoing laboratory tests. Details of the installation at the gasifier reactor are shown in the photographs that follow. Figure 7 shows the gasifier control room. The electrical control units shown earlier in Figure 4 are mounted in the console shown in Figure 8 together with a dual-beam oscilloscope which can be used to display the A and B outputs simultaneously. Next to the reactor wall is the explosion proof container within which are mounted the three radiometer heads as shown earlier in Figure 4. The internal layout is as previously shown schematically in Figure 2.

Initial measurements made by this instrumentation while monitoring the gasification process are described in the paper by John Walsh.

3. MICROPROCESSOR-CONTROLLED SPECTRAL SCANNING RADIOMETER SYSTEM

Introduction

Part I of this paper described the concept of using a spectral scanning radiometer to monitor the combustion process in the reactor and described laboratory tests and an initial test on the reactor. At the end of that paper was mentioned the potentialities of using a new generation scanning radiometer (then in prototype stage) to monitor and analyze the combustion process.

This development of this Model 12-550 Mark II microprocessor-controlled radiometer system has been completed and is now in production. The concepts of using it for combustion process monitoring, analysis and control will be reviewed here.

System Design Summary

The Model 12-550 Mark II Research Radiometer System has been described elsewhere in considerable detail, and only the most outstanding features will be reviewed here.

The system consists of an Optical Head and a Programmable Control Unit (PCU) as shown in Figure 9. Both are modularized for cost-effective functional flexibility.

The Optical Head has available a variety of interchangeable collecting optics as well as a processor-controlled chopper, a programmable filter wheel, and modular detector-preamplfier units. The Optical Head shown in Figure 9 has the vertical protruding module for a liquid-nitrogen cooled detector. Other types of detectors do not require this extension.

Modularity is also incorporated in the Programmable Control Unit which contains all the circuits necessary to process the signal from the Optical Head according to the requirements of the applications. Rapid modification to the needs of specific applications is aided by the use of a circuit board rack with provisions for mounting up to 16 individual circuit boards.

Most signal processing is done digitally, although analog outputs are also offered as a convenience.

Four powerful capabilities result from the use of a microprocessor at the base of system architecture. One, it provides such basic system functions as automatic switching of electrical attenuators, selecting chopper speed, and controlling the operation of the spectral filter system, scanning mirrors and accessory devices. Two, it provides the capabilities of automatic gain control, sample averaging and normalization. Three, it integrates the first two capabilities to the needs of the applications. Four, it conditions and processes input and output data to achieve interfacing with the selected computer and data display facilities. These capabilities are provided mainly by software which integrates system operation and adapts it to use as a radiometer, transmissometer, process control system or reflectometer.

Process Control Concept

Real-time process control by means of continuous spectral analysis is founded on a few basic principles. When infrared radiation is directed through a material, part of the energy is transmitted, part absorbed, and part reflected. The percentages of transmission, absorption and reflection vary with wavelength in a manner that is unique to the specific material. Consequently, the spectral response curve of a material serves as a "signature" that identifies a material even when it is intermixed with other materials. Extensive collections of such spectral response curves have been made for determining the concentrations of different materials in a mixture by spectral analysis.

It is characteristic of materials that in those spectral intervals in which they are good absorbers, they are also good emitters of radiant energy in that same wavelength interval. Thus, the spectral distribution curve of self-emitted radiation also serves as a unique signature for identifying a material. By techniques that will be described, the spectral characteristics of both absorption and self-emission can be determined simultaneously.

When a process is being conducted or a material is being produced, its spectral absorption or emission characteristics can be examined. If the process or product is such that a spectral analysis can be made, and if there are significant spectral variations as changes in the processing takes place, it may be possible to use this as a basis for real-time process control. The basic procedure is first to observe the nature of the spectral changes that take place. Then, spectral intervals, sequences and dwell times are selected to determine from these spectral analyses the nature and degree of the process or product change away from the "ideal". This result is used with closed-loop servo control techniques to "zero in" the system back to its ideal form of operation.

Figure 10 schematically shows the basic arrangement of a gasifier monitoring, analysis and control system based upon spectral scanning, and Figure 11 shows a photograph of a prototype arrangement in which a 4-foot tube is substituted for the reactor. The process control environment illustrated is that which exists within the reactor. The inputs are coal plus the gases required to produce and control combustion. The outputs are heat which can be extracted in a variety of manners, plus combustible gas and a variety of by-products. Control is exercised by regulating the rate at which the individual inputs are supplied to the reactor and the rates at which the outputs are removed.

While the process is taking place within the reactor, radiation from a blackbody source at known temperature is chopped at a specific frequency to identify it from other radiation. This radiation is directed through the processing chamber to the Optical Head. If necessary, the radiation can be intensified by means of supplementary optics that beam it through the atmosphere of the chamber.

Program preparation begins with manually adjusting the process to the ideal condition. Then, a spectral scan is made of absorption and emission and the data is recorded on the printer. In turn, each of the inputs, outputs and operating conditions is then varied while spectral scans are made and data is recorded. For each of these conditions, the nature of adverse affects on the desired products are noted and quantized in a manner appropriate to the process. Then appropriate combinations of input, output, and environmental conditions are changed, and the effects are recorded. Next, the process control team and computer programmer create a control scenario in which a specific deviation is identified from a spectral scan variation away from the "ideal" and they devise the most efficient sequence for adjusting input, output, environment conditions to restore the "ideal". This is done for all reasonable combinations. These various control scenarios are then written into a general control program for the computer that is to be used, and this program is installed into the computer.

During operation, the computer scans the spectral absorption and emission from the process, identifies the type of deviation taking place, and feeds out the program control signals to bring the process back to its ideal condition.

Conclusion

The microprocessor-controlled spectral radiometer system has the built in capabilities to simultaneously perform the functions of the previously described integrated radiometric system and ratio processor. In addition, it is capable of making simultaneous emission and transmission measurements of the gasification process and to interface with a computer to perform control functions.

REVIEW

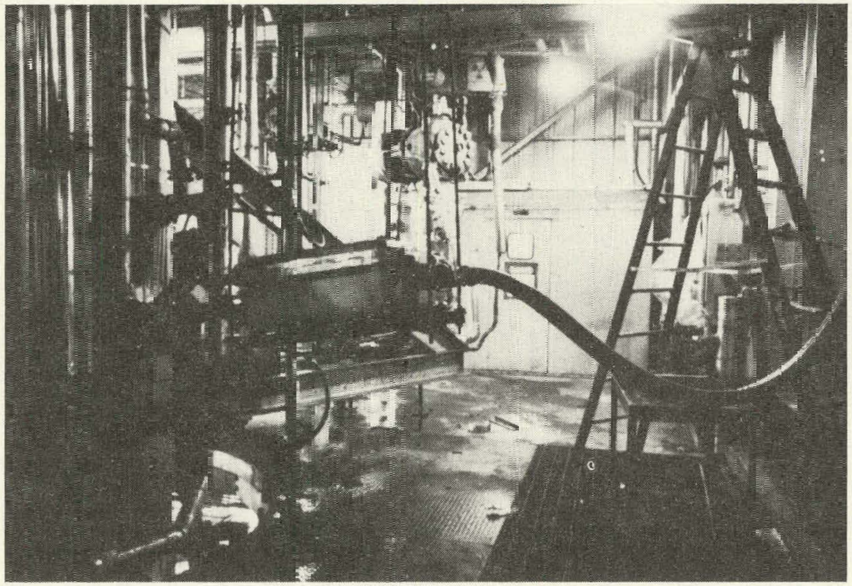
Instrumentation has been developed and installed to scan the radiation inside a coal gasifier reactor. A summary was presented of the initial system used for flame detection for alarm functions and temperature measurements and for monitoring the gasification process by spectral scanning. Also reviewed was the more recent addition of a ratio processor designed to permit the system to make gasifier temperature measurements by the two-color method. Finally, there was reviewed the concept and laboratory tests of a microprocessor-controlled spectral-scanning system for continuous gasifier process control.

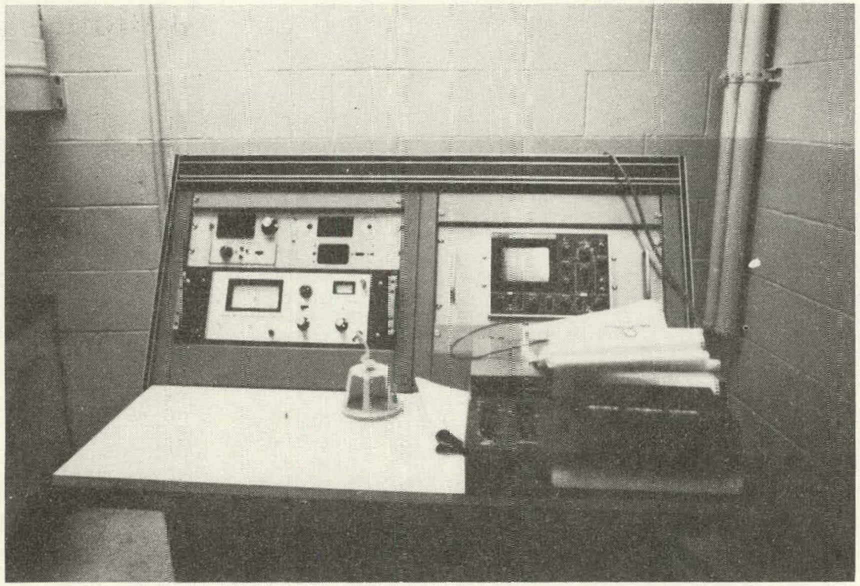
REFERENCES

1. Zweibaum, F., Integrated Radiometric System for Gasifier Temperature Measurements. Proceedings of the 1978 symposium on Instrumentation and Control for Fossil Demonstration Plants.

2. Demarest, F., Zink, D., Zweibaum F., A New Microprocessor-Based Multipurpose Electro-Optical Measurement System. SPIE Proceedings Vol. 218-05.

3. Zweibaum, F., Fully-Integrated On-Line Process Control System Employing Microcomputer-Based IR Spectrometer. SPIE Proceedings Vol. 170-24.





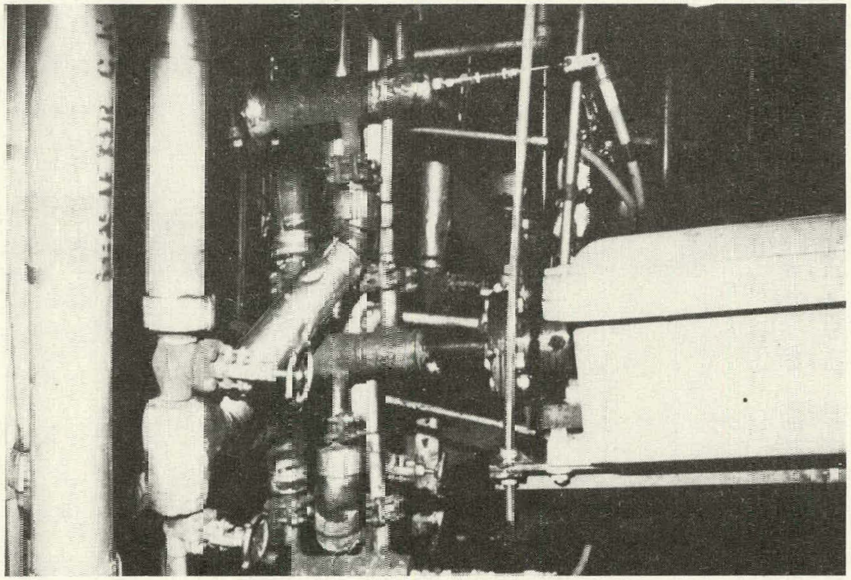
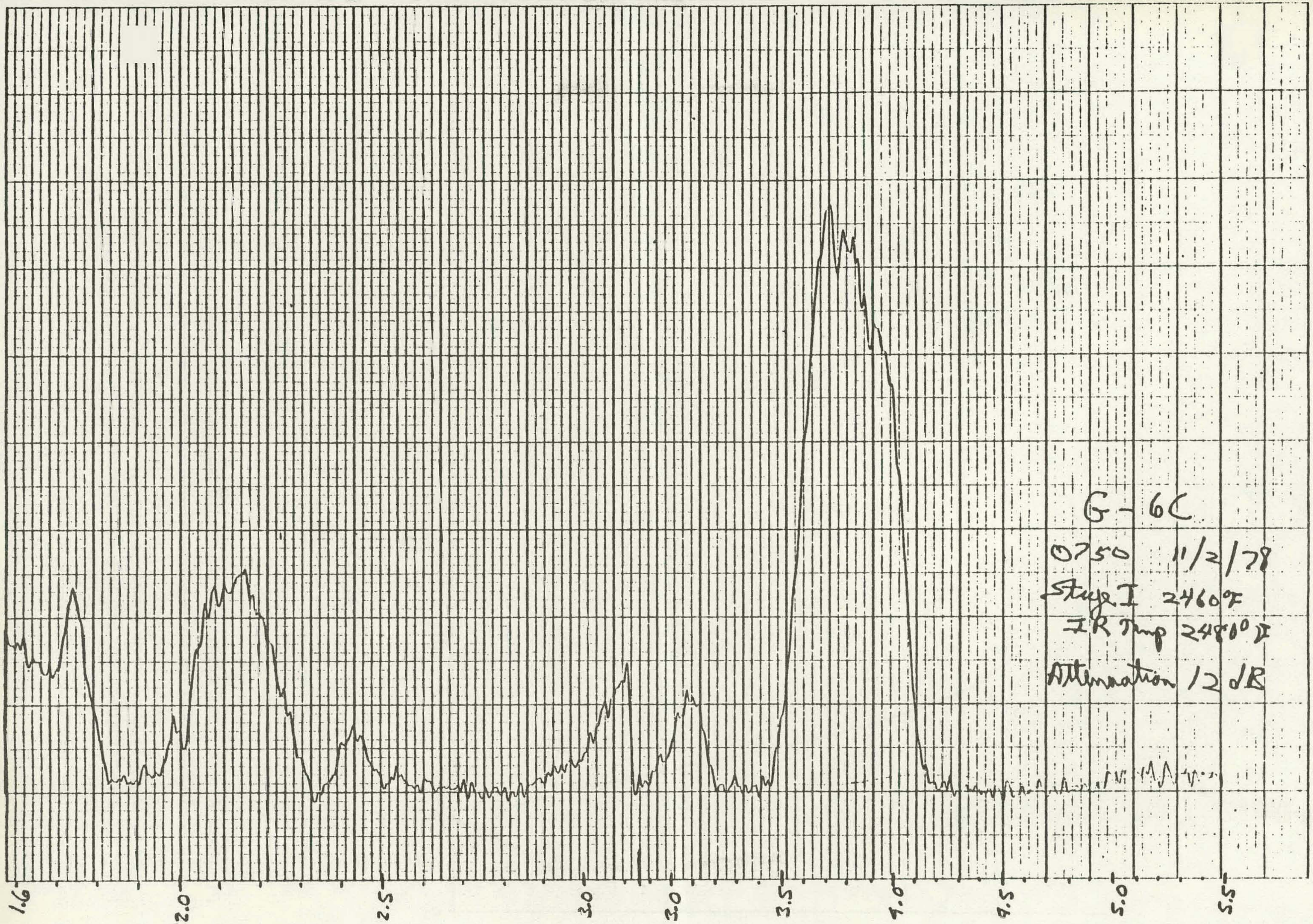


Figure 1. Original Installation on Coal Gasifier Reactor

Upper left photo shows reactor wall at extreme left. Sensors are in explosion-proof enclosure left of center, with curved cable at right going 300 feet to control and readout panels.

Upper right photo shows control and readout panels. Special scanner panel is at lower left. Temperature monitor panel is at upper left with provision for additional similar panel immediately at right. Right black panel is X-Y scope for displaying output of spectral scanner.

Lower left photo shows explosion-proof enclosure center right with sighting tube extending to left into reactor.



G-6C

0750 11/2/78

Stage I 2460°F

IR Temp 2480°F

Attenuation 12 dB

Figure 1 Part D. Spectral Scan of Gasifier Reactor During Operation Shows Combustion Products

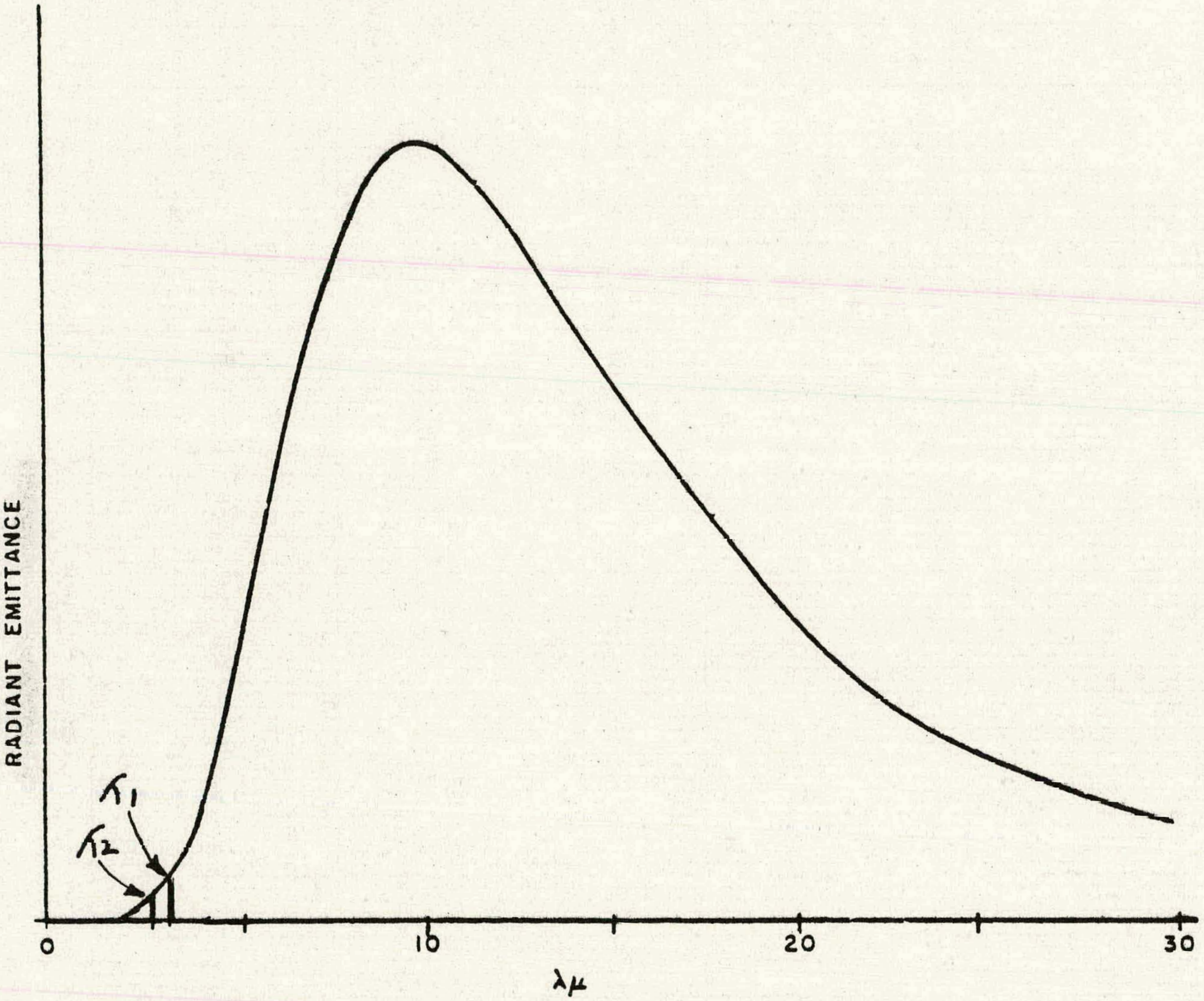


Figure 2 Part A. Principle of Two-Color Temperature Measurement. In the total radiation method energy is measured under a large portion of the blackbody curve shown here. Variations in emissivity lower curve height and lower the apparent measured temperature. In the two color method energy is measured in only two narrow adjacent bands, and taking the ratio cancels the effect of emissivity in the computation.

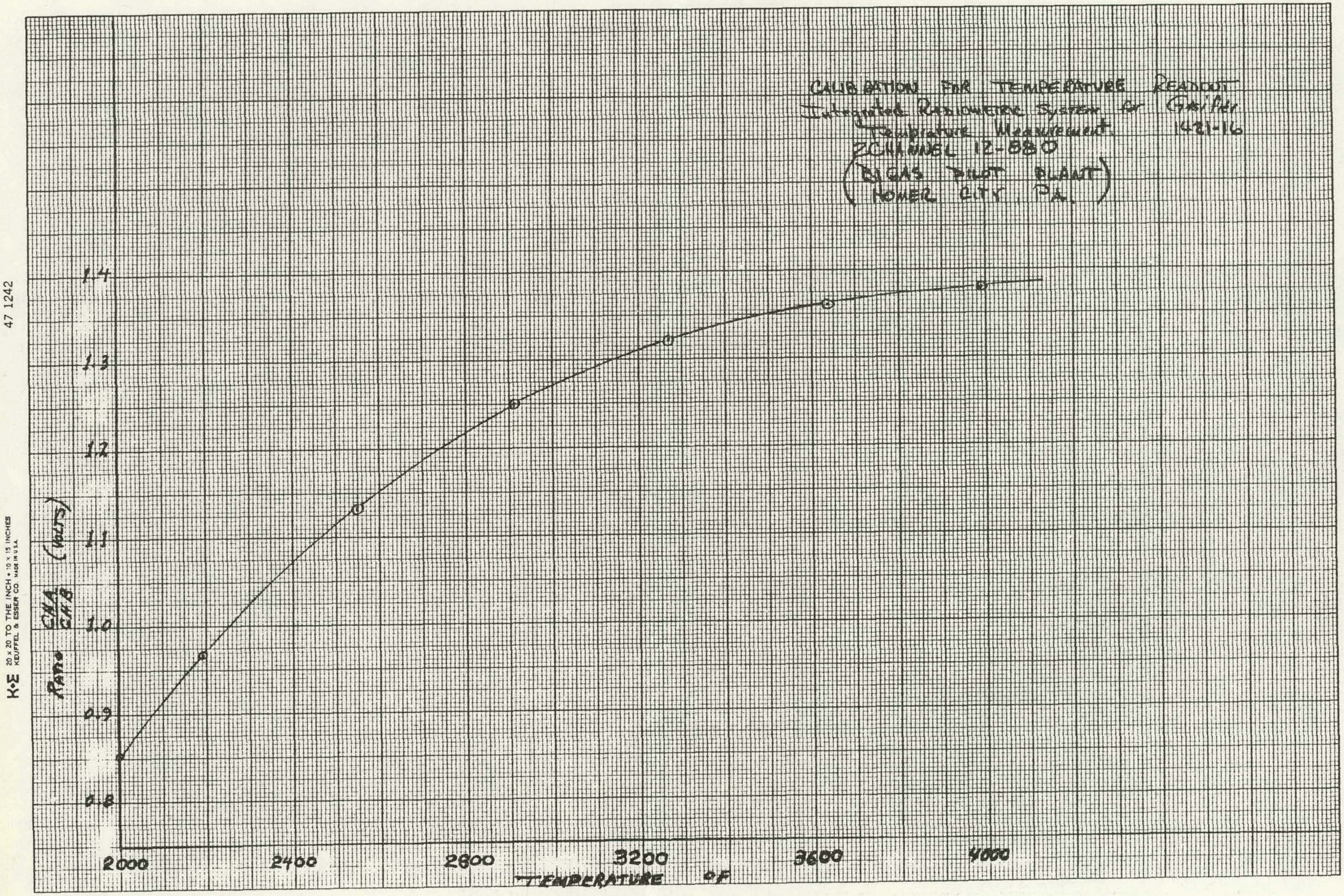


Figure 2 Part B. Calibration Curve of Delivered Ratio Processor. The curve shows the output of Channel A divided by that of Channel B for blackbody targets from 2000°F to 4000°F.

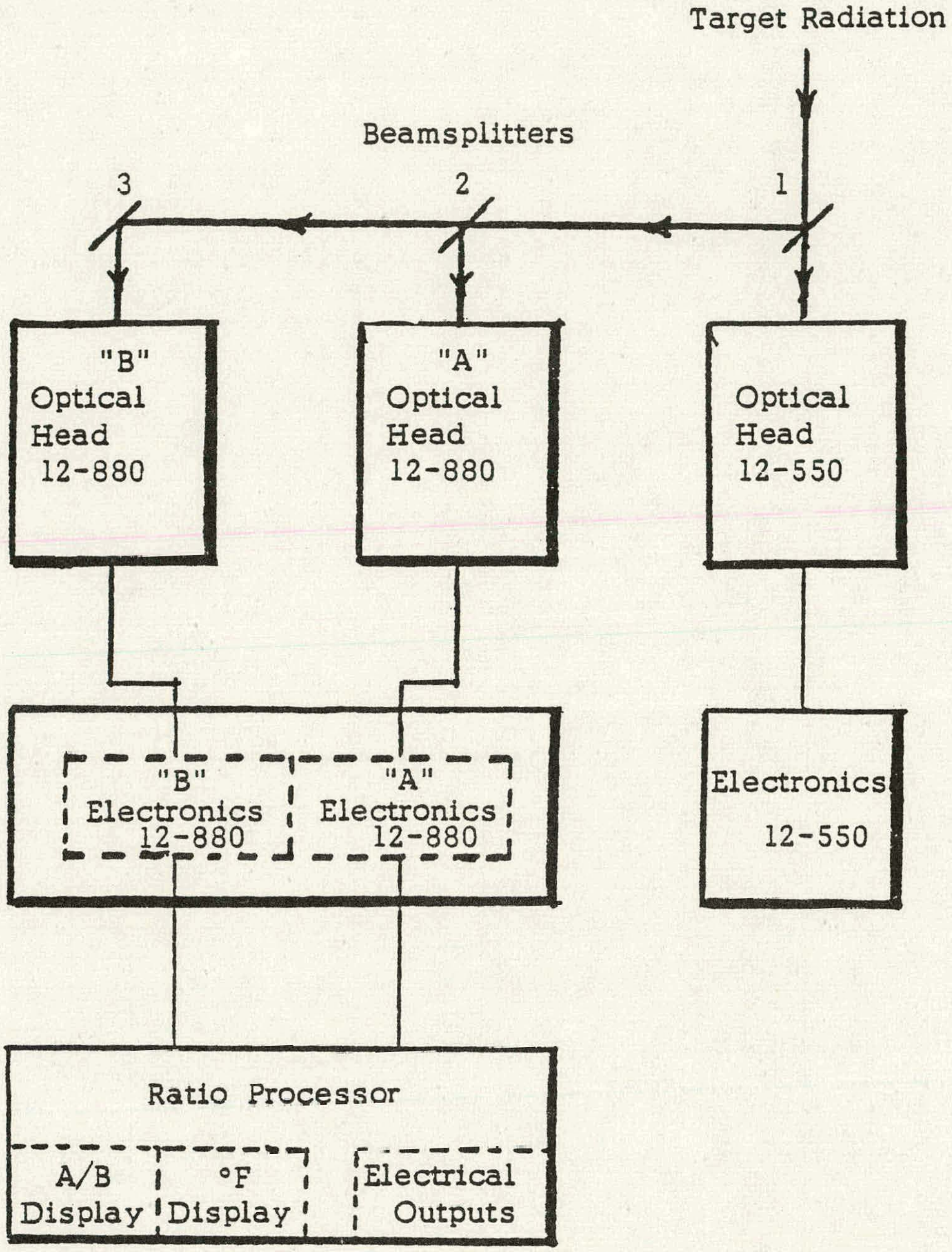


Figure 3. Place of Ratio Processor in Integrated System for Gassifier Temperature Measurements.

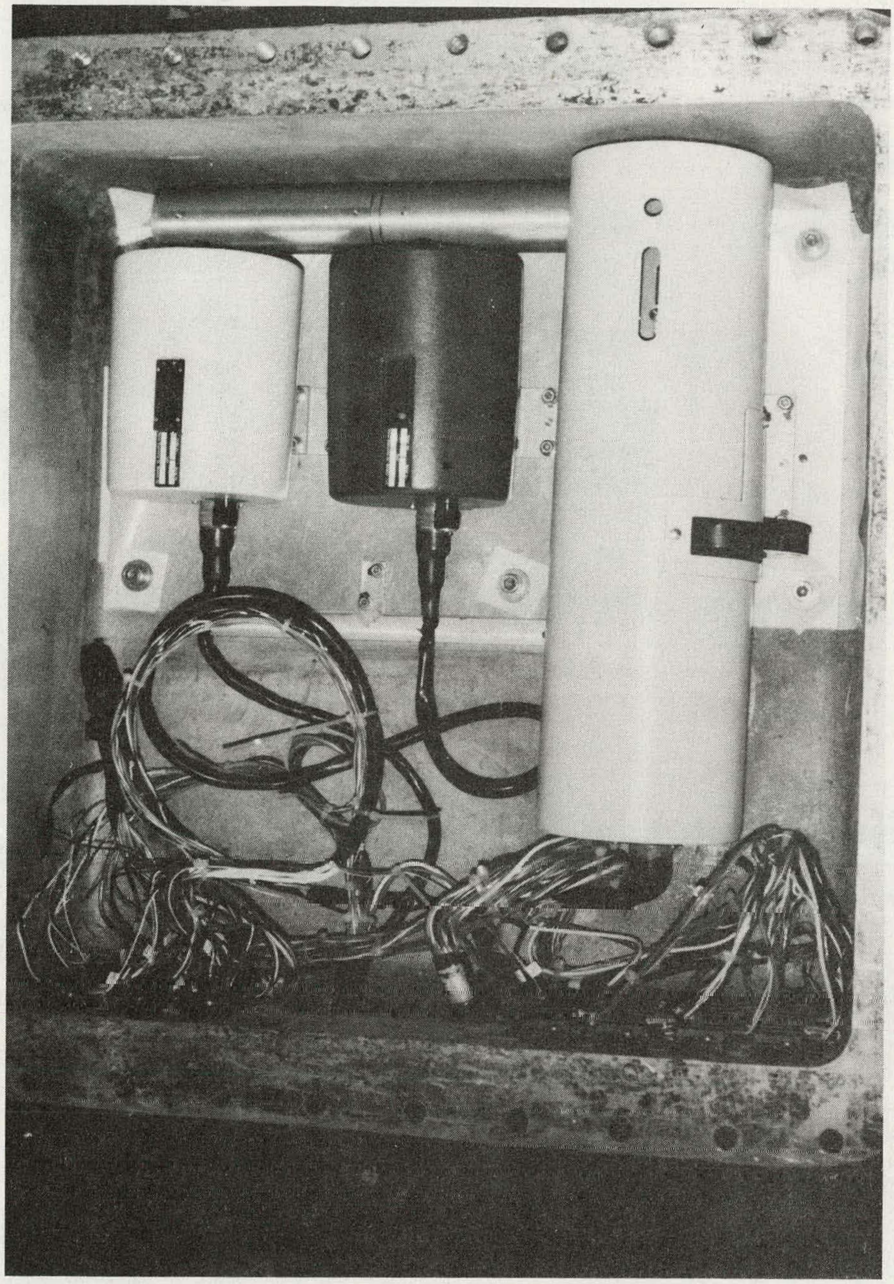


Figure 4. Three Optical Heads of Integrated System Installed in Explosion-Proof Container. Layout duplicates that shown in upper part of Figure 3.

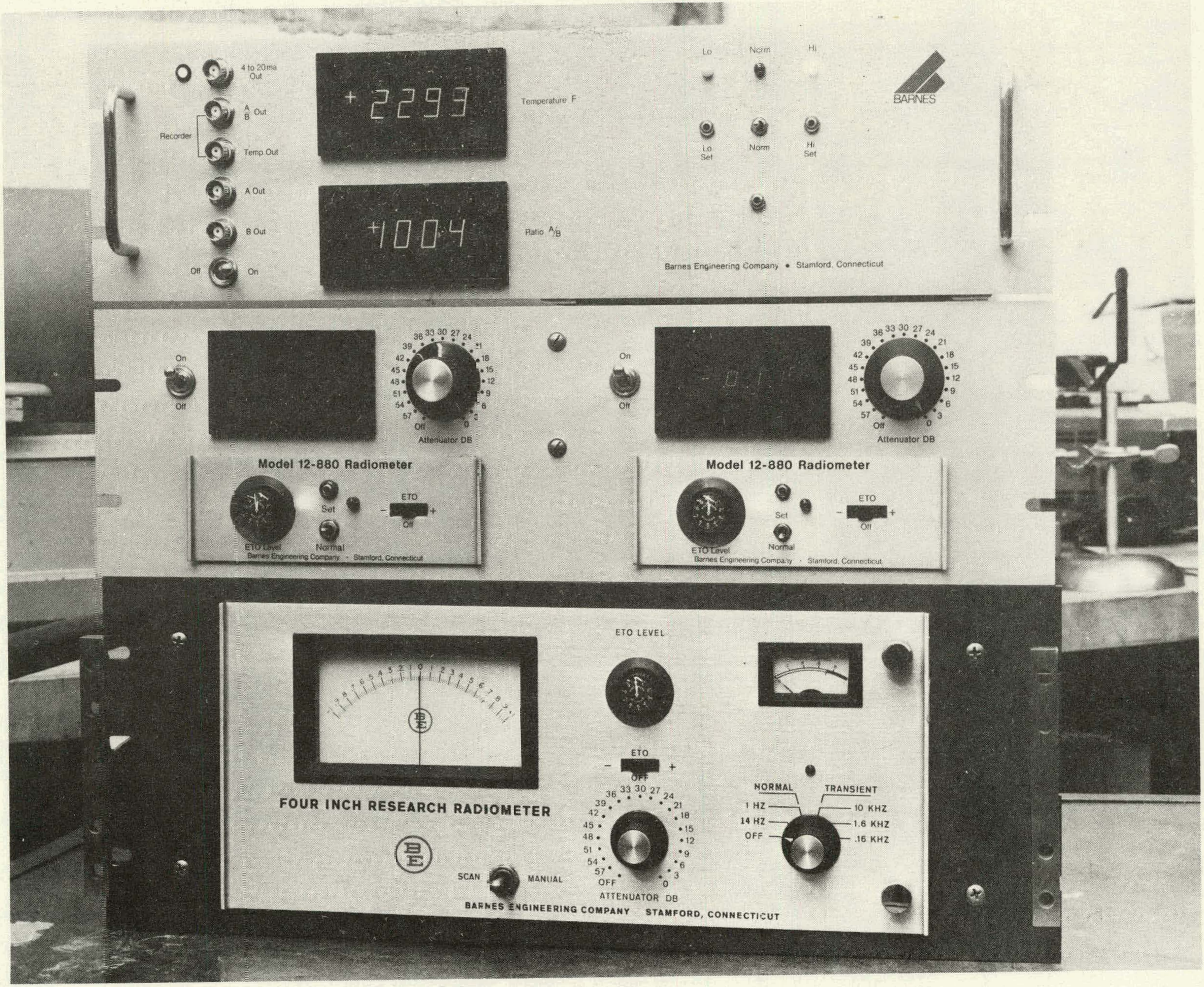


Figure 5. Electronic Units Prior to Final Installation.

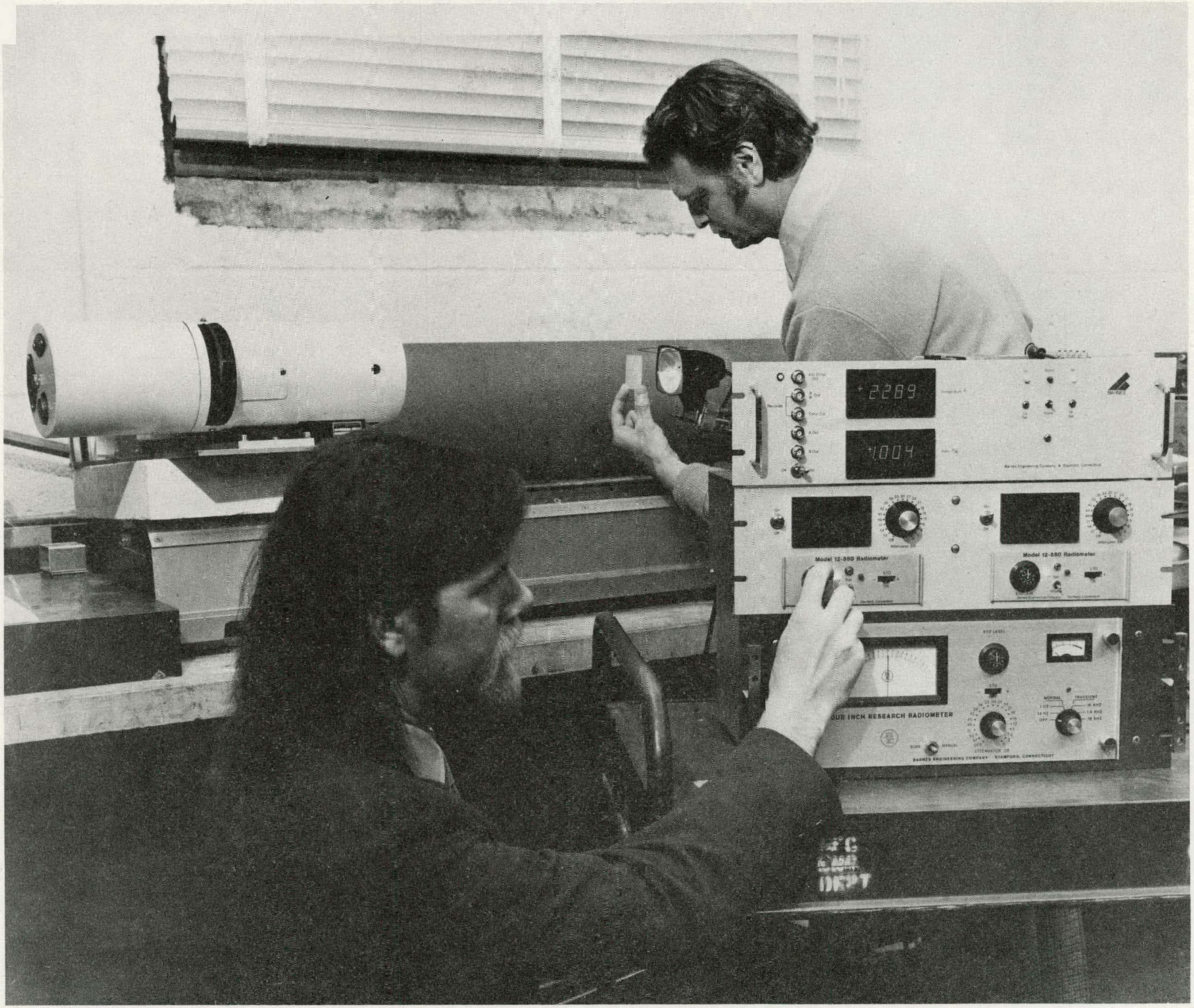


Figure 6. Integrated System During Laboratory Tests. Scanner head is shown at left.

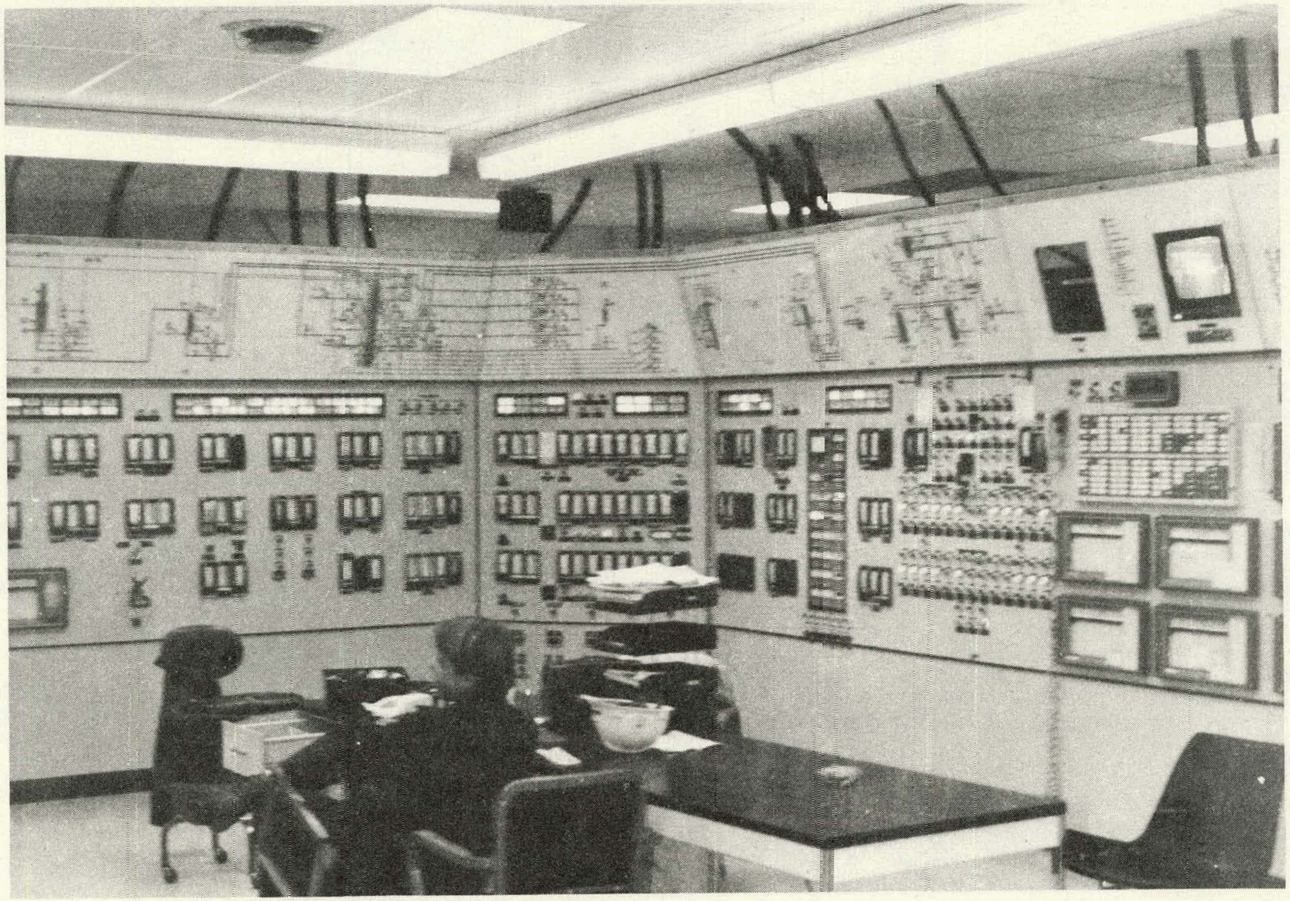


Figure 7. Gasifier Reactor Control Room

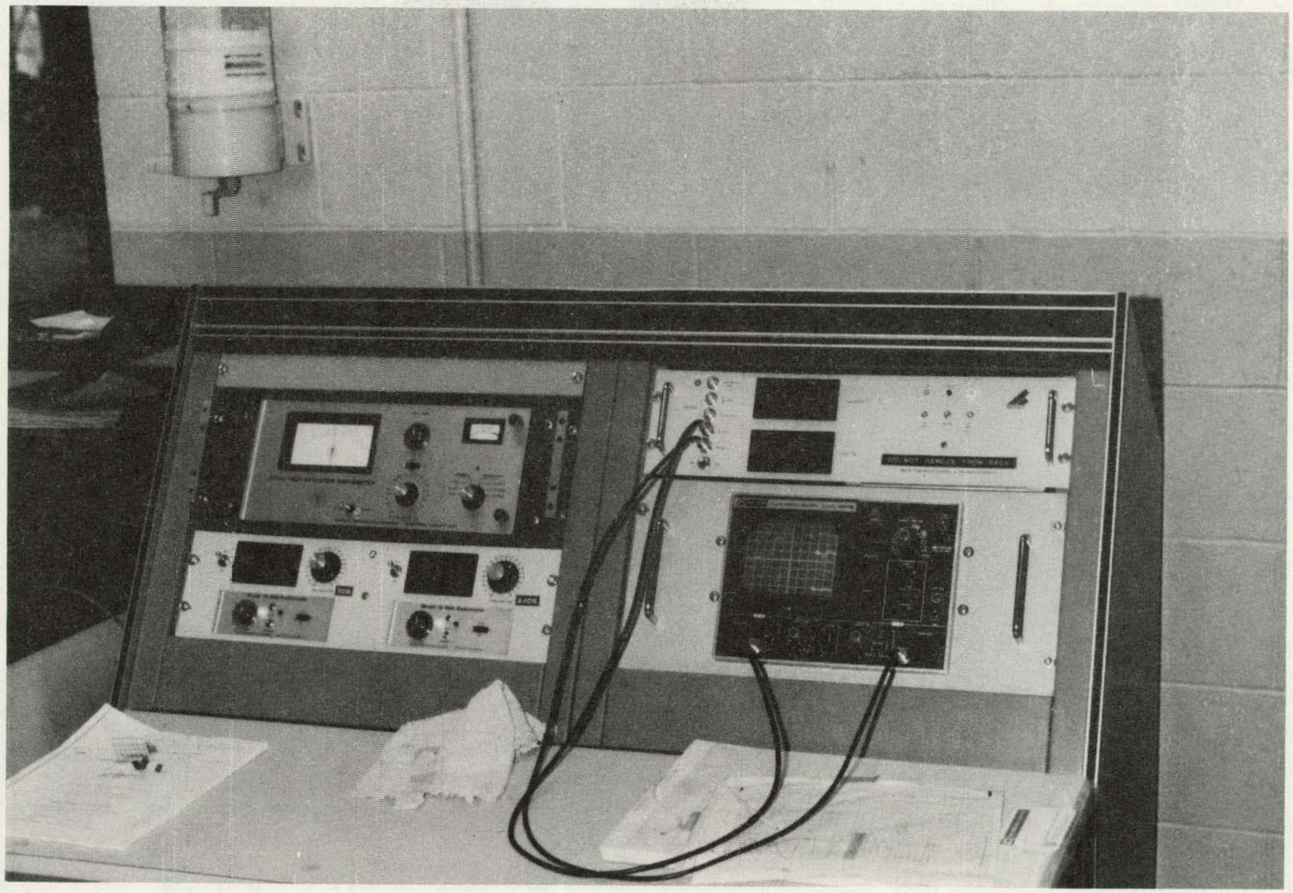


Figure 8. Closeup of Integrated Radiometric System Control Console

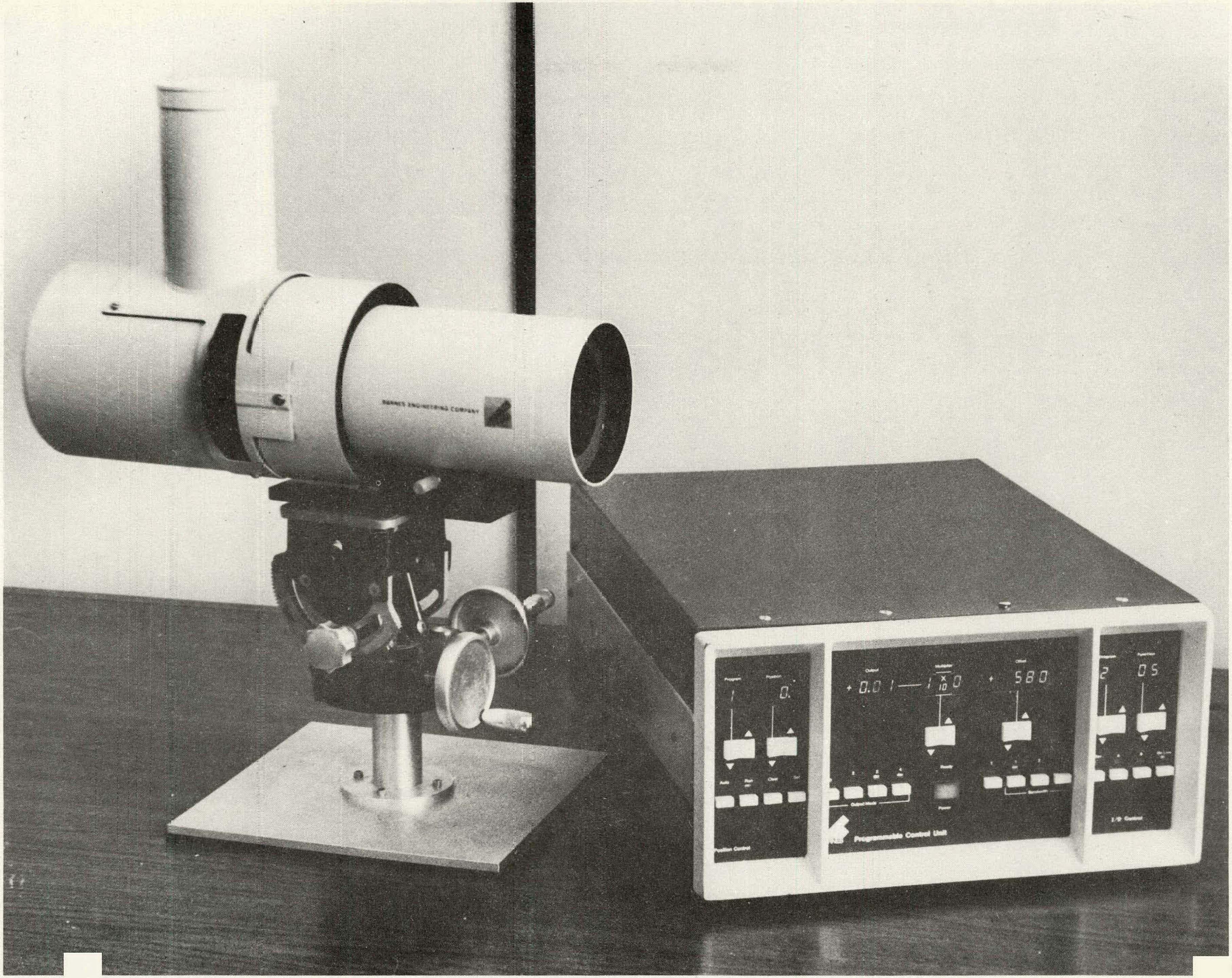


Figure 9. Optical Head and Programmable Control Unit of Mark II Research Radiometer System

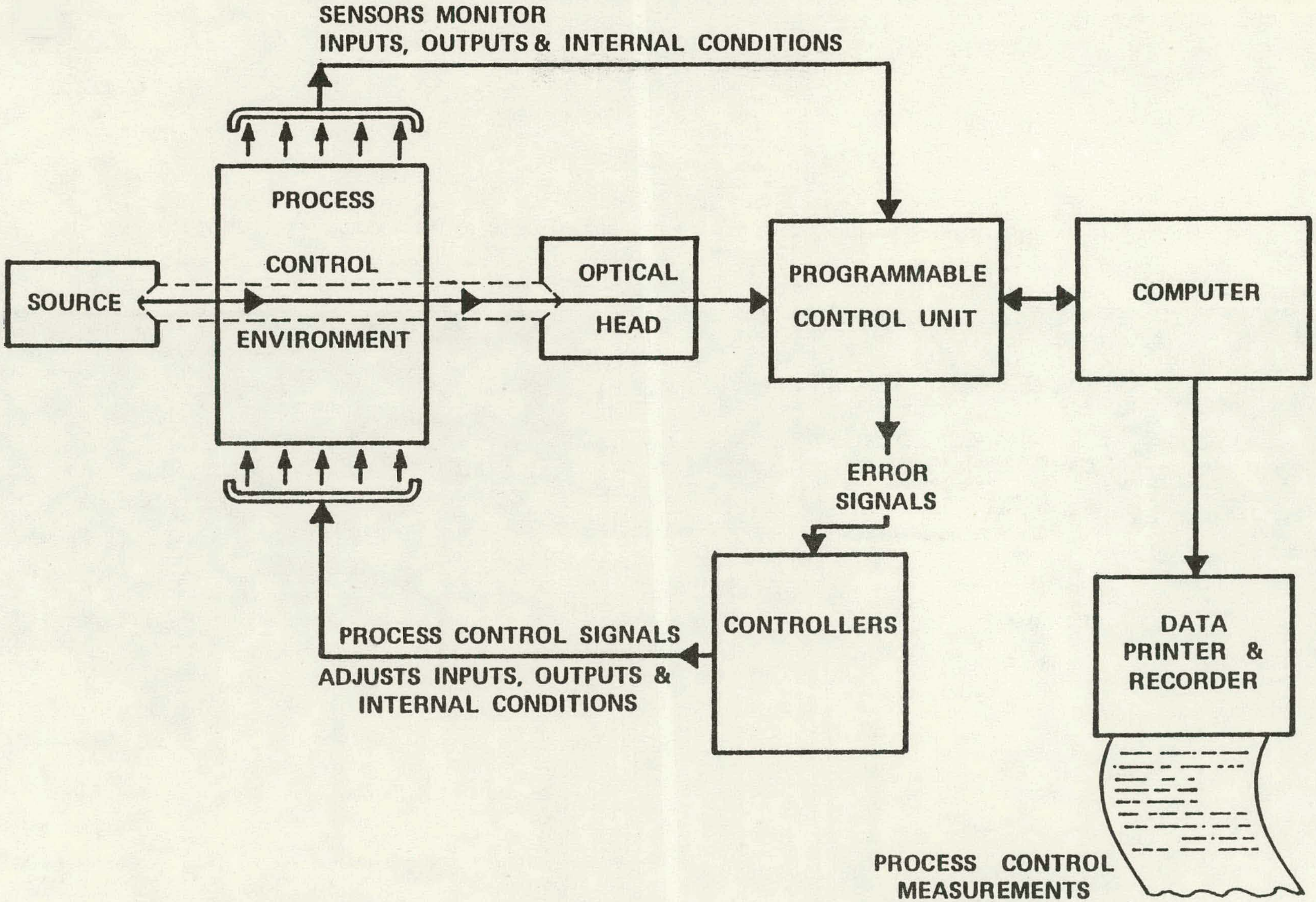


Figure 10. Functional Schematic of Gasifier Monitoring, Analysis and Control System

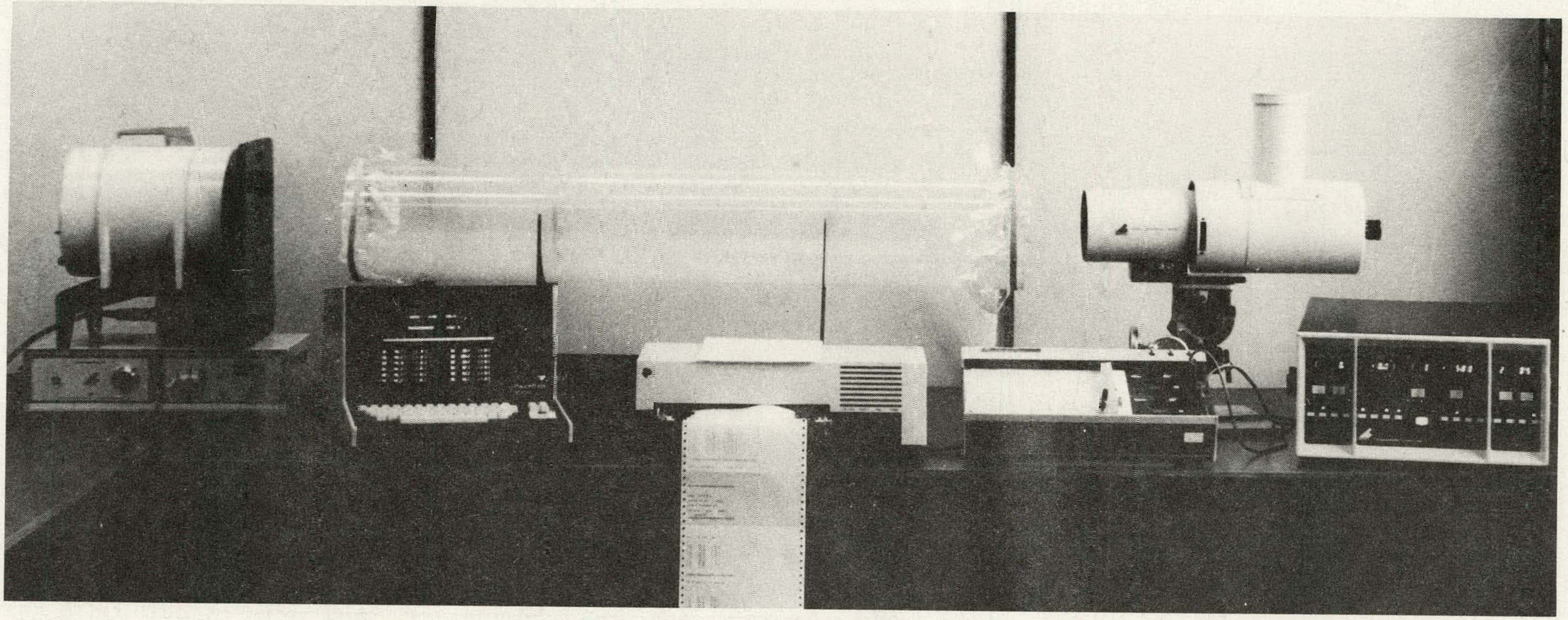


Figure 11. Prototype of Monitoring, Analysis and Control System Shown in Figure 10.

AN OVERVIEW OF THE EXPANDING REQUIREMENTS FOR THE MEASUREMENT OF PRESSURE, FLUIDIZED BED LEVEL, AND TEMPERATURE ABOVE 1500 PSI and 1500 F IN FOSSIL ENERGY PROCESSES

M. Berdahl and J. Inskeep
Jet Propulsion Laboratory
Pasadena, California 91103

ABSTRACT

Measurement of temperature, level and pressure above 1500 F and 1500 PSI in coal reactors and combustors presents unique problems. Current approaches to these problems are reivewed and future requirements arising from the emerging technology are discussed.

SCALING LAWS FOR GAS-PARTICLE FLOW THROUGH VENTURIS

C.T. Crowe and J. Lee
Mechanical Engineering Department
Washington State University
Pullman, WA 99164

ABSTRACT

The two most important flow parameters relating to the flow of a gas-solids mixture in a venturi are Stokes number and loading. Experimental studies at Washington State University have shown that the pressure drop increases linearly with loading and decreases monotonically with increasing Stokes number. The experiments were done with glass beads and pulverized coal. These data clearly demonstrate the importance of Stokes number in extrapolating data from bench-scale experiments to full-scale designs.

INTRODUCTION

The flow of gases with suspended particles is encountered in many industrial and energy-related industries such as the gasification and combustion of pulverized coal, air-pollution control systems, pneumatic conveying of granular materials, and in many other industrial processes. Common to these industries is the need to reliably monitor the solids-flow rate. For example, balancing the coal-air mixture to burners fired by pulverized coal requires an accurate flow meter. Because several feeder ducts are normally used in parallel, flow conditions tend to drift over a period of time from their correct settings, so continuous monitoring and regulating are needed to maintain efficient combustion and economy. Currently, the solids flow rate into a furnace is monitored by the speed of a coal-feeder belt or by the pressure drop across the pulverizer. These methods are not amenable to fine adjustment, nor adaptable to sensitive feed-back control systems. Hence, there is a need to have reliable flow metering devices which are inexpensive and sufficiently accurate for industrial applications.

Many different designs and concepts for metering pneumatically conveyed gas-solids mixtures have appeared in the literature. These include the application of radioactive tracer and β-ray absorption techniques (1), microwave techniques (2) and the measurement of charge generated by the particle cloud (3). Another type of meter is the target, or impact,flowmeter (4), to measure the momentum imparted by the particle cloud and, knowing the particle velocity, calculate the particle mass flow rate. A rather novel extension of the impact flowmeter is the annular venturi meter (5) which was designed to measure the flow rate of both phases but the scatter in the data lends the scheme unattractive. For industrial applications, one is interested in simple, inexpensive and reliable meters which provide acceptable accuracy.

Pressure inferential devices, such as the orifice, flow nozzle and venturi, are used extensively in industry to monitor the flow rate of single-phase fluids. However, the application of these meter types to measure the flow rate of particle suspension flows has not been entirely successful. Carlson, et al. (6) developed a venturi-orifice combination to monitor both gas and particle flow rates which performed well on bench-scale experiments, but failed for large scale systems. The reason for the failure was the unawareness of the primary independent variables relating to gas-particle flow through constrictions. Subsequent studies (7) indicated that the pressure drop across a venturi with gas-particle flow depends primarily on Stokes* number and particle loading. The fact that Stokes number is dependent on meter size explains the failure of Carlson's device to function as expected for a large scale system. An extensive review of the literature by Washington State University (8) revealed that virtually no data were available which demonstrated the dependence of pressure drop on Stokes number and loading over a sufficiently wide range for practical use. For example, the Stokes number for gas-particle flow in a line conveying pulverized coal is about .5, yet the data available were for Stokes numbers ten times as large. Moreover, most of the available data did not provide adequate information on particle size.

During the past two years, an extensive experimental and analytic program has been underway at Washington State University to measure the effect of Stokes number, loading and meter geometry on pressure drop in a venturi. This paper presents the results of this study.

INITIAL PARAMETRIC STUDY

Dimensional analysis of gas-particle flow through a venturi shows that the pressure drop is given by

$$\frac{\Delta P_{TP}}{\Delta P_G} = f\ (Re_g,\ Re_p,\ St,\ Z)$$

---

*Stokes number is the ratio of particle relaxation time to gas residence time.

where ΔP_{TP} is the pressure drop for gas-particle flow, ΔP_G is the pressure drop for gas flow alone and Re_g, Re_p, St and Z are the Reynolds number of the gas, the Reynolds number of the particle, the Stokes number and the loading. Using the quasi one-dimensional numerical model developed at WSU (9), it was found that the predicted pressure drop for the useful range of flow conditions depends only weakly on Re_g and Re_p but is very strongly influenced by St and Z.

Stokes number is defined as

$$St = \rho_p d_p^2 U_g / 18 D_t$$

where ρ_p is particle material density, d_p is the particle diameter, U_g the inlet gas velocity, μ the viscosity and D_t the throat diameter. If the Stokes number is small, then the particle relaxation time is small compared to the gas relaxation time and the particle can respond quickly to the changes in gas velocity so a near "equilibrium" condition is maintained. In this case, the two-phase mixture acts like a heavy gas with an attendant large pressure drop. On the other hand, a large Stokes number implies little time available for change of particle velocity and the mixture behaves as a particle-free gas.

The loading parameter (Z) is the ratio of the particle mass flow rate to gas mass flow rate.

The geometrical parameter describing the ASME venturi geometry is β-ratio; i.e., the ratio of throat diameter to pipe diameter.

EXPERIMENTAL PROGRAM

The experimental set-up is shown schematically in Fig. 1. The facility consists of an inlet air supply, metered by an orifice, a powder feeder to feed particles into the airstream, a gas-particle mixing section, a test section for installation of venturis and flow nozzles, and, finally, a series of cyclone separators to remove particles from the airstream and return them to the powder feeder. The pressure differential data are recorded by slant tube alcohol manometers. The pressure taps are continuously purged by an inconsequentially small air flow to prevent dust accumulation in the taps. A photograph of the experimental rig is shown in Fig. 2.

A Coulter counter was used to provide detailed measurements of particle number and size.

Three types of spherical particles were used in the experiment: microballoons, glass particles and Ballotni impact beads. Also, Utah coal as obtained from a commercial pulverizer was used. The maximum feed rates of each

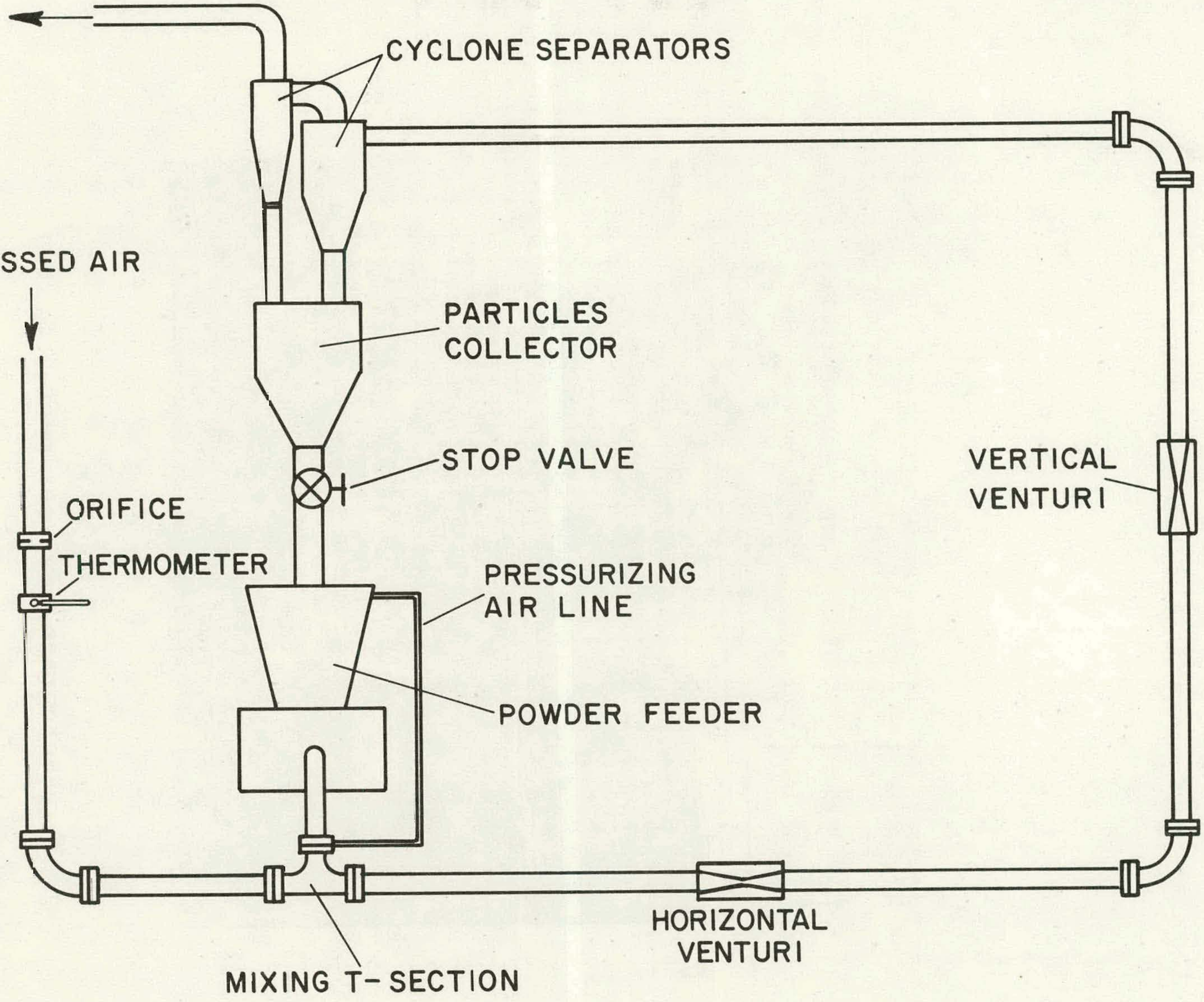


Fig. 1 Schematic Diagram of Test Rig

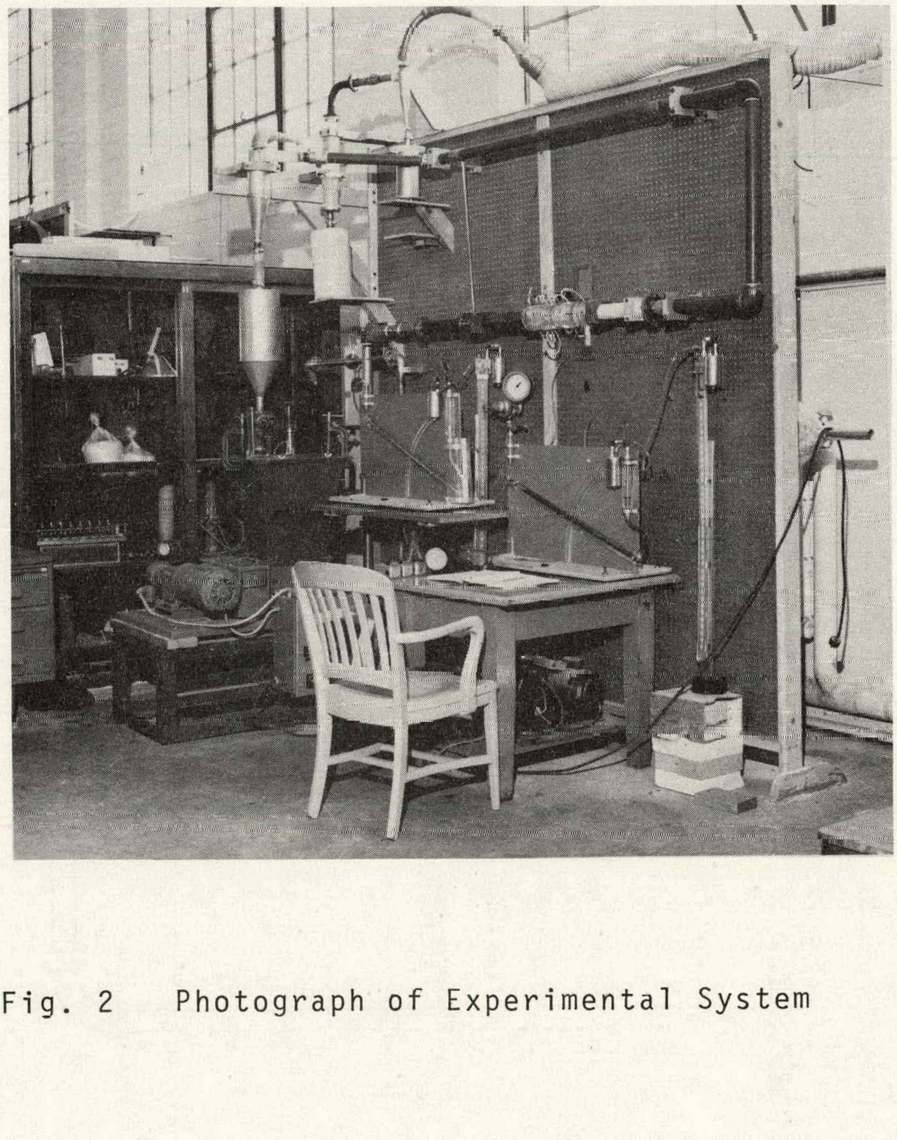


Fig. 2 Photograph of Experimental System

particle type and their characteristics are shown in the table. Using these particles in the experimental rig provided Stokes numbers from .15 to 13 and loadings from 0 to 2.

Particle type	Maximum Feed Rate (lbm/sec)	Density (lbm/ft^3)	Mass Median Diameter (μm)	Shape
Microballoons	0.02	20	29	spherical
Glass beads	0.15	180	36	spherical
Ballotni-impact beads	0.17	151	65	spherical
Pulverized coal	0.06	84	43	irregular

Table: Characteristics of Particles Used in Experiments

The majority of the experiments were conducted with the standard ASME venturi geometry with β-ratios of .5, .6, and .7. The venturi with a β-ratio of .6 was tested in both the horizontal and vertical orientations. A standard ASME flow nozzle with a β-ratio of .6 was also tested with pulverized coal.

The tests were carried out for a given particle type and meter geometry by maintaining a constant air mass flow rate and increasing the powder feed rate to increase the loading. The tests were repeated for other air flow rates to establish the repeatability of the data. Typical data from these runs are shown in Fig. 3. One notes a linear variation of the pressure drop with loading which persisted throughout. Thus, the results for each test can be expressed as a single parameter reflecting the slope of the line. The parameter chosen was $P_r = (\Delta P_{TP}/\Delta P_G - 1)/Z$ which is identified as the pressure ratio parameter and where ΔP_{TP} is the pressure drop with gas-particle flow, ΔP_G is the pressure drop for air flow only through the nozzle and Z is the loading.

A summary of the experimental results for the pressure ratio parameter versus Stokes number is shown in Fig. 4. One notes that for ASME venturis, the pressure ratio parameter monotonically decreases with increasing Stokes number. There also appears to be no significant difference between the horizontal and vertical orientations. For Stokes number up to 5 there appears to be no effect of β-ratio, which implies that β-ratio is not a significant parameter in this range. However, for Stokes numbers around 10, the nozzles with larger β-ratio tend to have a smaller pressure ratio parameter; specifically, the venturi with a β-ratio of .7. Insufficient data exists at this time to explain this trend or to determine if it extends to higher Stokes

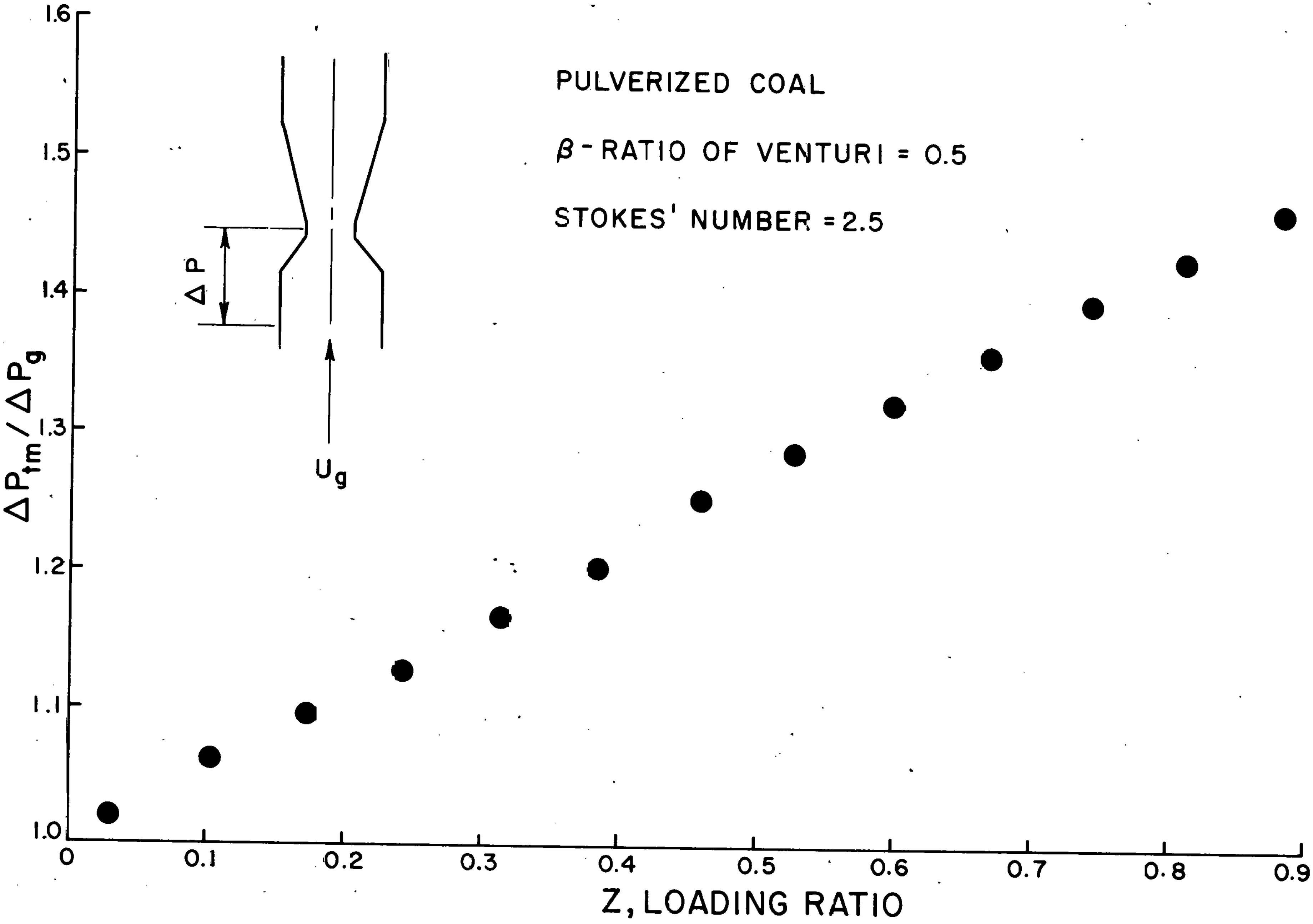


Figure 3. Pressure Drop vs. Loading for Pulverized Coal.

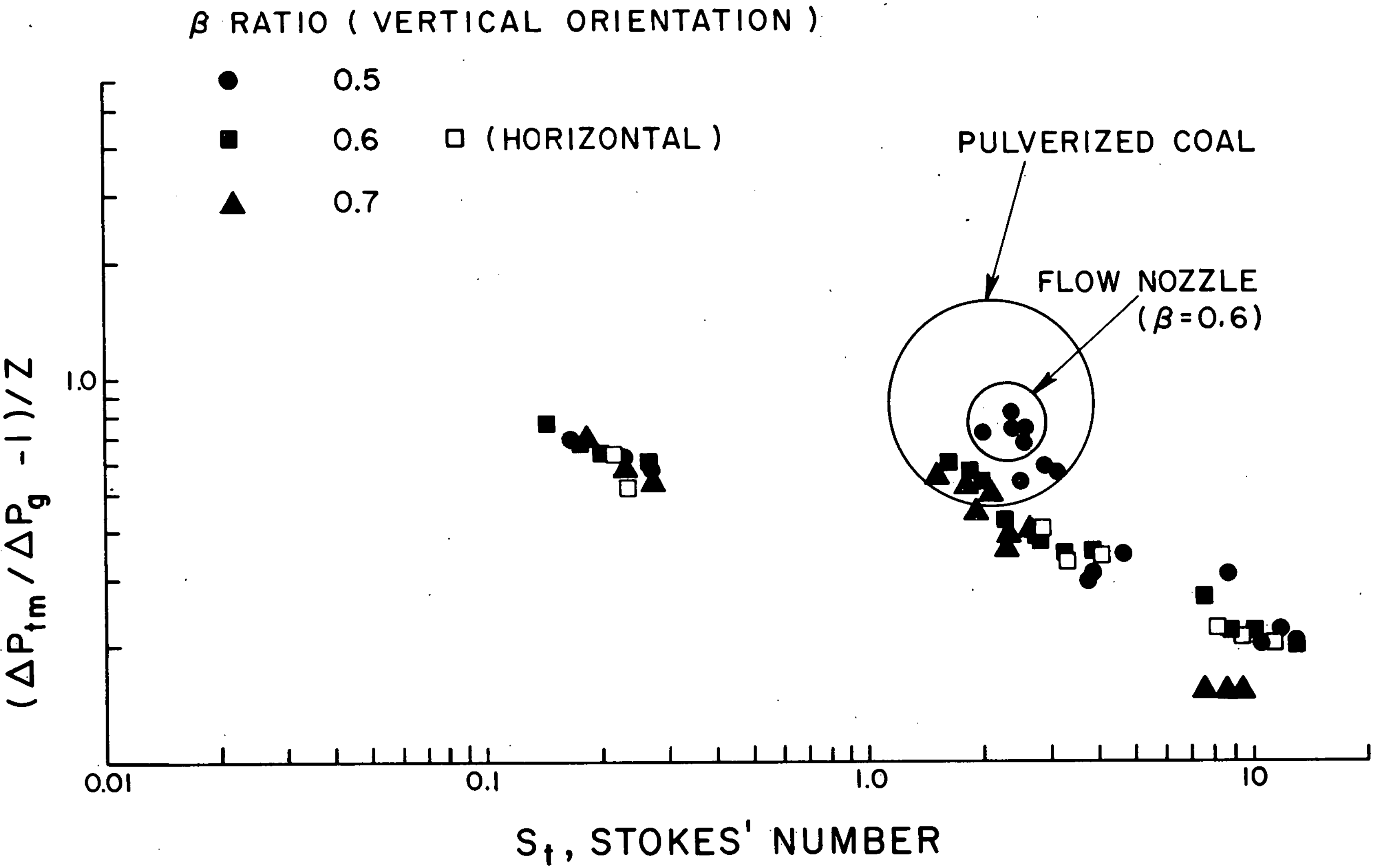


Figure 4. Summary of Data for Pressure Ratio Parameter.

numbers. This information is important in scaling up laboratory data to full size designs.

One also notes on Fig. 4 that the data for pulverized coal falls above those for spherical glass beads. This is consistent with the higher drag coefficient characteristic of irregularly-shaped coal particles (10). More data and supporting numerical studies are needed to determine if the difference can be attributed solely to aerodynamic drag.

A small number of tests were also performed with an ASME flow nozzle design using pulverized coal. The pressure drop is distinguishably higher than that for a conventional venturi. The upstream geometry of the flow nozzle is much different than that of the venturi which probably accounts for the observed trend. Once again, more data and supporting numerical studies are needed to understand the observed trends.

The predictions of the quasi one-dimensional numerical model developed at WSU were compared with the experimental results. The one-dimensional model consistently overpredicts the pressure drop, but shows better agreement at low Stokes number than at high Stokes number. This trend is attributed to the effect of particle channeling; that is, the tendency of particles to accumulate near the nozzle axis. A two-dimensional model, now nearing completion, tends to bear this out.

To summarize, this study has shown that

1) Stokes number and loading are the two dominant nondimensional parameters relating to pressure drop of gas-particle flows in venturis,
2) pressure drop at a fixed Stokes number varies linearly with loading,
3) the pressure ratio parameter decreases monotonically with increasing Stokes numbers,
4) venturi β-ratio appears to have an effect only at high Stokes numbers, and
5) pulverized coal has a higher pressure ratio parameter than spherical particles at a Stokes number of approximately two.

CONCLUSION

The observed sensitivity of pressure drop to solids loading demonstrates the viability of the venturi as a flowmeter for gas-particle flows. Also, the dependence of the pressure ratio parameter on Stokes number demonstrates the importance of Stokes number as the scaling parameter. Either bench-scale models must have Stokes numbers near that of the prototype or information is needed for Stokes number effect to extrapolate bench-scale data to predict full scale performance. Further information needed includes an extended and more complete range of Stokes numbers, the effects of particle size distribution and shape, more data for flow nozzles and a general two-dimensional numerical model to explain the observed trends and to predict performance with flow conditions for which data are unavailable.

ACKNOWLEDGEMENTS

The support of NSF Grant ENG77-09855 for this program is acknowledged.

REFERENCES

1) Hours, R.M. and Chen, C.P., "Application of Radioactive Tracers and β-Rays Absorption Techniques to the Measurement of Solid Particles Velocity and Space Concentration in a Two-Phase Air-Solid Flow at High Mass Rate," Paper B3, Third Intl. Conf. on the Pneumatic Transport of Solids in Pipes, BHRA Fluid Engineering, Cranfield, England, 1976.

2) Howard, A.V., "A Microwave Technique for Monitoring the Mass Flow Rate of Pneumatically Transported Solids," Paper S3, Third Intl. Conf. on the Pneumatic Transport of Solids in Pipes, BHRA Fluid Engineering, Cranfield, England, 1976.

3) Beck, M.S., Hobson, J.H. and Mendies, P.J., "Mass Flow and Solids' Velocity Measurement in Pneumatic Conveyors," Paper D3, First Intl. Conf. on the Pneumatic Transport of Solids in Pipes, BHRA Fluids Engineering, Cranfield, England, 1971.

4) Nugent, C.W., "The Impact Flowmeter," Bulk Solids in Transit, Proceedings of Conference Sponsored by the Institution of Mechanical Engineers, Londdon, 1974.

5) McVeigh, J.C. and Craig, R.W., "Metering of Solid/Gas Mixtures Using an Annular Venturi Meter," Paper D2, First Intl. Conf. on the Pneumatic Transport of Solids in Pipes, BHRA Fluid Engineering, Cranfield, England, 1971.

6) Carlson, H.M., Frazier, P.M., and Engdahl, R.B., "Meter for Flowing Mixtures of Air and Pulverized Coal," Trans. ASME, July 1953, p. 943.

7) Boothroyd, R.B., Flowing Gas-Solids Suspension, Chapman and Hall, 1971.

8) Sharma, M.P., "Numerical and Experimental Study of Gas-Particle Flows in Orifices and Venturis: Application to Flowmeter Design," Ph.D. Thesis, Washington State University, 1977.

9) Sharma, M.P. and Crowe, C.T., "A Novel Physico-Computational Model for Quasi One-Dimensional Gas-Particle Flows," Jnl. of Fluids Engr., 100, 3, pp. 343-349, 1978.

10) Clift, R., Grace, J.R., and Weber, M.E., Bubbles, Drops and Particles, Academic Press, 1978.

Dup

X-RAY IMAGING OF COAL DERIVED PRODUCTS*

M. G. Thomas
D. G. Sample
Sandia Laboratories, Albuquerque, NM 87185

ABSTRACT

X-ray techniques have been developed for imaging flow and/or flow restrictions in coal liquefaction processing equipment. The two main areas addressed are (1) real time imaging of coal slurry flow characteristics, and (2) the residual buildup of coke and inorganic residues in piping, particularly tees and elbows, that carries the initial coal slurry and the products. The system used for (1) includes a 100 kv power supply, a Magnaflux 150 X-ray tube, photomultiplier detector, and a strip-chart recorder. Water and oxygen were used to simulate a two-phase coal-slurry/gas system. Analysis of the X-ray absorption has distinguished stratified, bubble, and slug flow, and the frequency and size of the gas displacements allow void volume determination. System (2) utilizes a Balteau portable X-ray unit and class II film. Phase boundaries between gas/coal derived liquids/coal are distinguishable and residue buildup has been detected in piping, tees, and elbows. These techniques are intended for use with existing equipment without the need for modifications.

INTRODUCTION

Coal liquefaction requires heating coal/solvent slurry at high temperatures, $> 400^{\circ}C$, and pressure, $\sim$ 2000 psi hydrogen, with and without catalysts, to form liquid products. The Department of Energy is currently supporting specific processes in coal liquefaction--H-Coal, SRC I and SRC II, EDS, and process research. The high temperatures and pressures, plus the continuous operation make in situ monitoring of these processes difficult. Nondestructive X-ray analysis has been applied to the analyses of

---

*This work supported by the U.S. Department of Energy.

several problems associated with coal liquefaction--solid/liquid separation, blockages in equipment caused by coke buildup, and flow characteristics. Our studies have been designed to allow for the use of portable equipment and real time imaging, and require no modification of existing equipment.

Studies

Experiments were performed in two specific areas; (1) static problems: a) coking deposits and other types of residue buildup which cause plugging in tees, elbows, and valves, b) erosion of equipment due to the circulation of slurries; and (2) dynamic problems: a) the determination of flow characteristics in two- and three-phase flow, and b) directly related, the detection of phase boundaries and settling rates in solid/liquid separations.

Static Problems

a) Coking deposits and residual buildup in lines. Material buildup in lines usually occurs around those areas of perturbed flow in equipment--around tees, elbows, valves, etc. These materials are usually composed of $\sim$ 50% inorganic material in an organic matrix. Thus, the material is of considerably higher density than the slurry that surrounds it. In Figure 1, we have depicted experiments where buildup was simulated and successfully detected and documented using portable X-ray equipment operating at 200 kv and class II X-ray film. Figure 2 shows a positive print obtained. The density difference in the simulated experiment was $\sim$ 10%, whereas 30-50% differences are expected in practice.(1)

b) Erosion of equipment. Although lines themselves are eroded very slowly, erosion of valve stems is a well documented problem that plagues both small and large scale processes.(2,3) Figure 3 shows a positive print of a photo and a radiograph of a "failed" valve obtained from Sandia's continuous flow liquefaction reactor.[4] The "v" notch is clearly visible in the

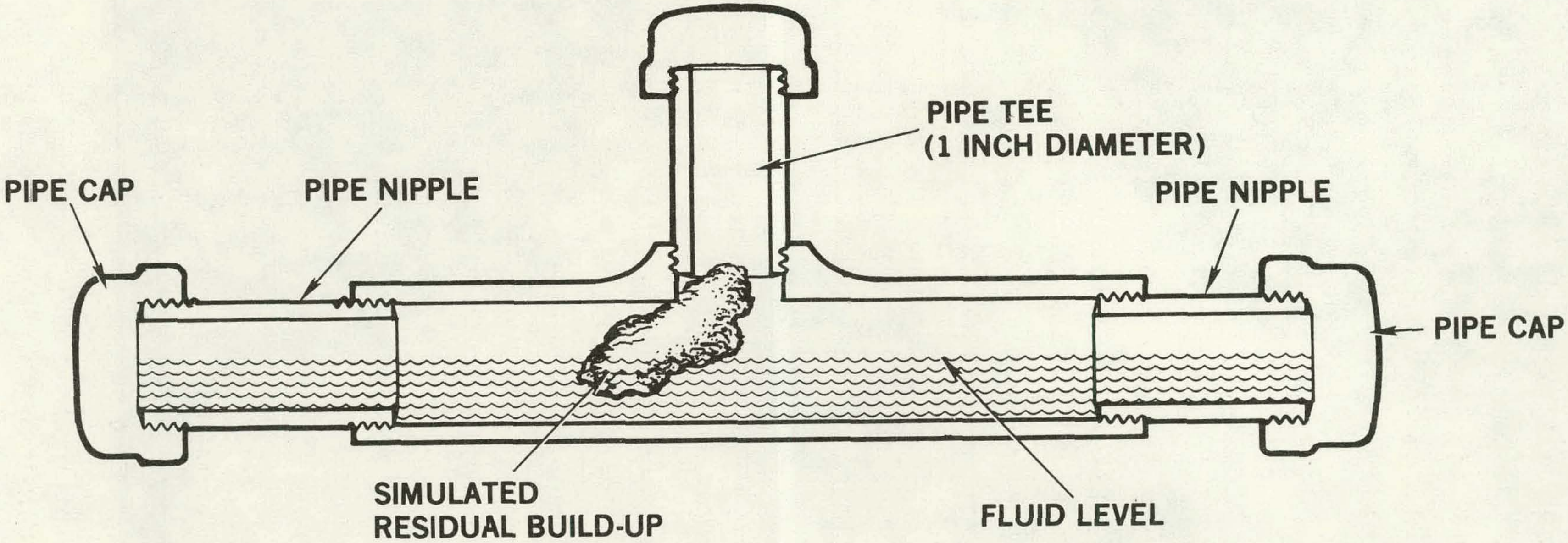


Figure 1 - Line drawing showing a simulated buildup of material in high pressure stainless steel tubing.

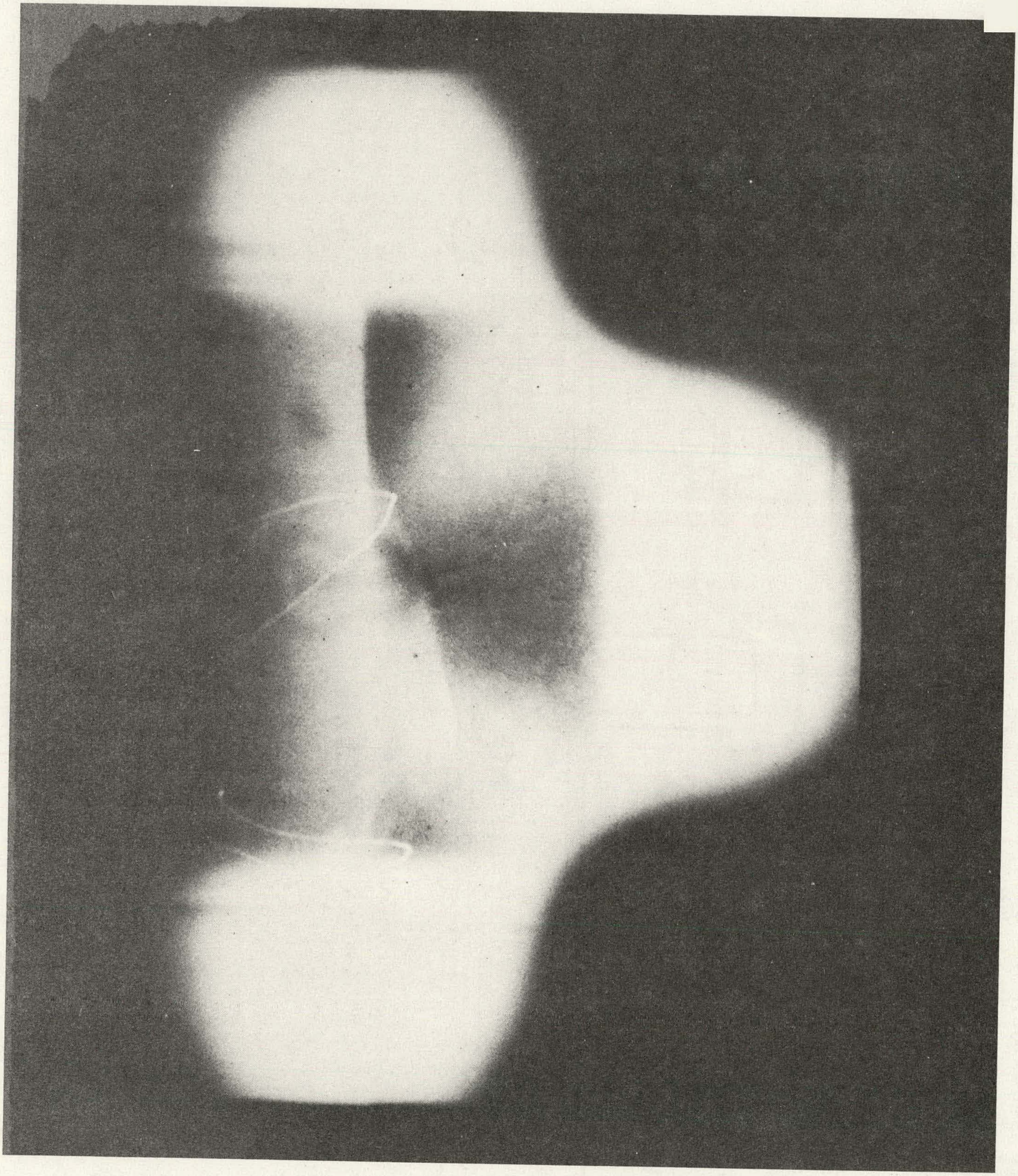


Figure 2 - Positive print of an X-ray showing coal deposited in pipe tee.

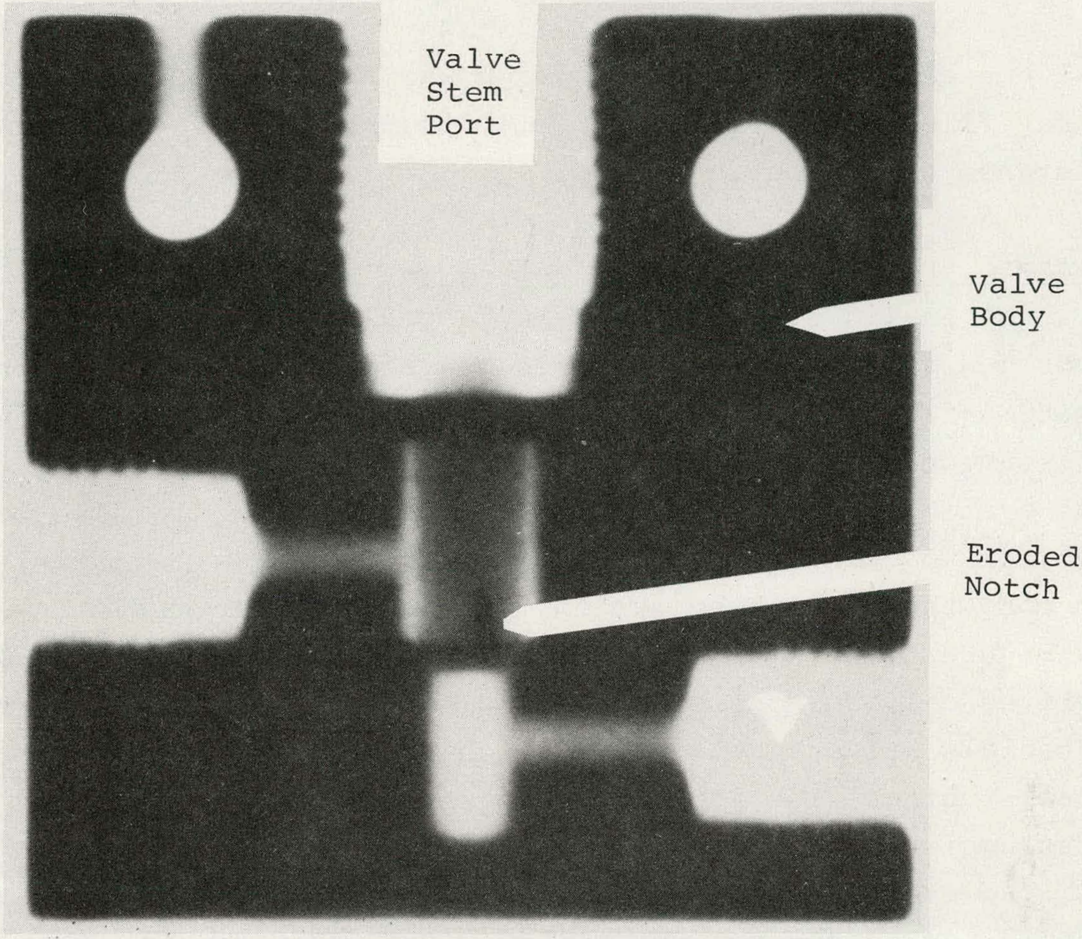
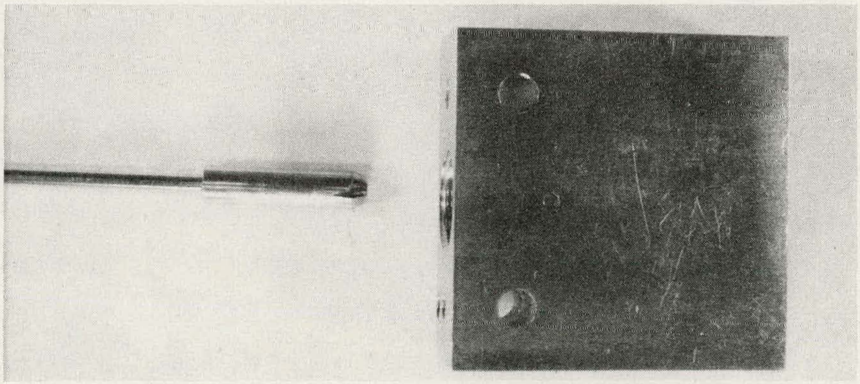


Figure 3 - (a) Positive Print of an X-ray showing the eroded notch in a valve stem in place, in a valve body.



(b) Photo of a valve body and stem.

valve encasement. The radiograph was obtained on fine grain X-ray film using a linear accelerator at 2.5 MeV and a shooting distance of 12 feet.

Dynamic Problems

a) In liquefaction systems, a coal/vehicle-oil slurry and hydrogen gas flow through pipes and reactors. The multiphase systems flow characteristics determine the residence time and, consequently, conversion. Since the physical properties of the system change throughout, the flow pattern may also be subject to change. In order to determine flow characteristics of more than a 1-phase system, the phases must be distinguishable. In Figure 4, we have a positive of an X-ray in which coal, coal-derived oil, and gas phases are clearly distinguished. The materials are encased in 0.25 inch 316 medium pressure stainless steel tubing. The densities of the materials are easily distinguished.

However, in a flow sequence, film radiography would only provide an average of the system. Real time documentation on film proved to be inadequate.(5) A scintillation detector connected to a recorder has provided adequate real time documentation. A specific experiment designed to measure flow characteristics in a two-phase system is depicted in Figure 5. A water tank with a submerged pump was used to circulate water through a closed system. The water from the tank was introduced into one leg of the tee, the opposite leg was connected to tygon tubing (used for visual verification) that went to the heavy wall pipe (tubing) under test. Air was introduced at specific times in a third leg. Water has approximately the same absorption as the oil produced in liquefaction processes and air simulates the gas. As seen in Figure 5, 90 kv X-rays are passed through the heavy wall 316 stainless steel tubing and are received by a radiation gage detector on the opposite side. The signal is amplified and projected on a recorder.

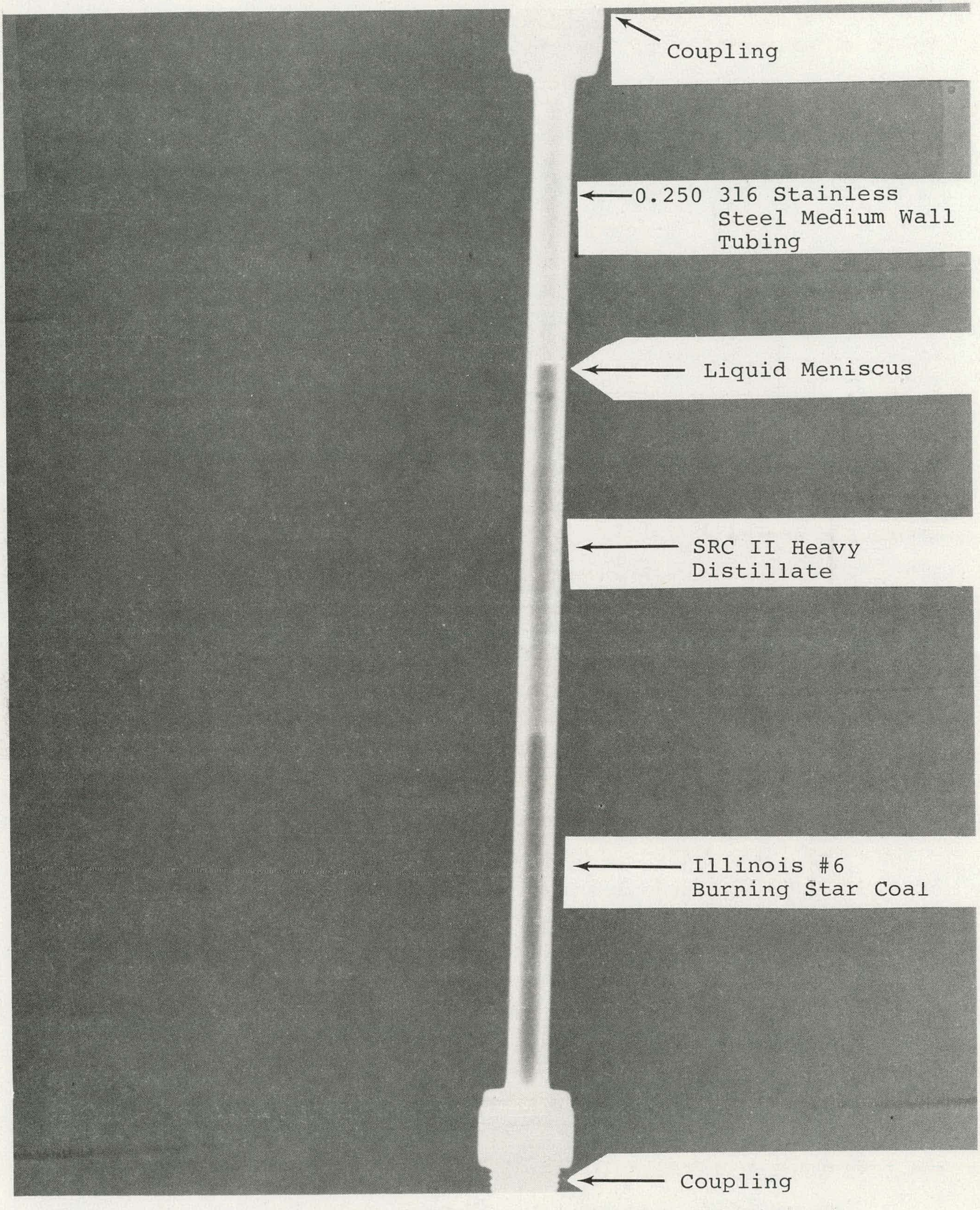
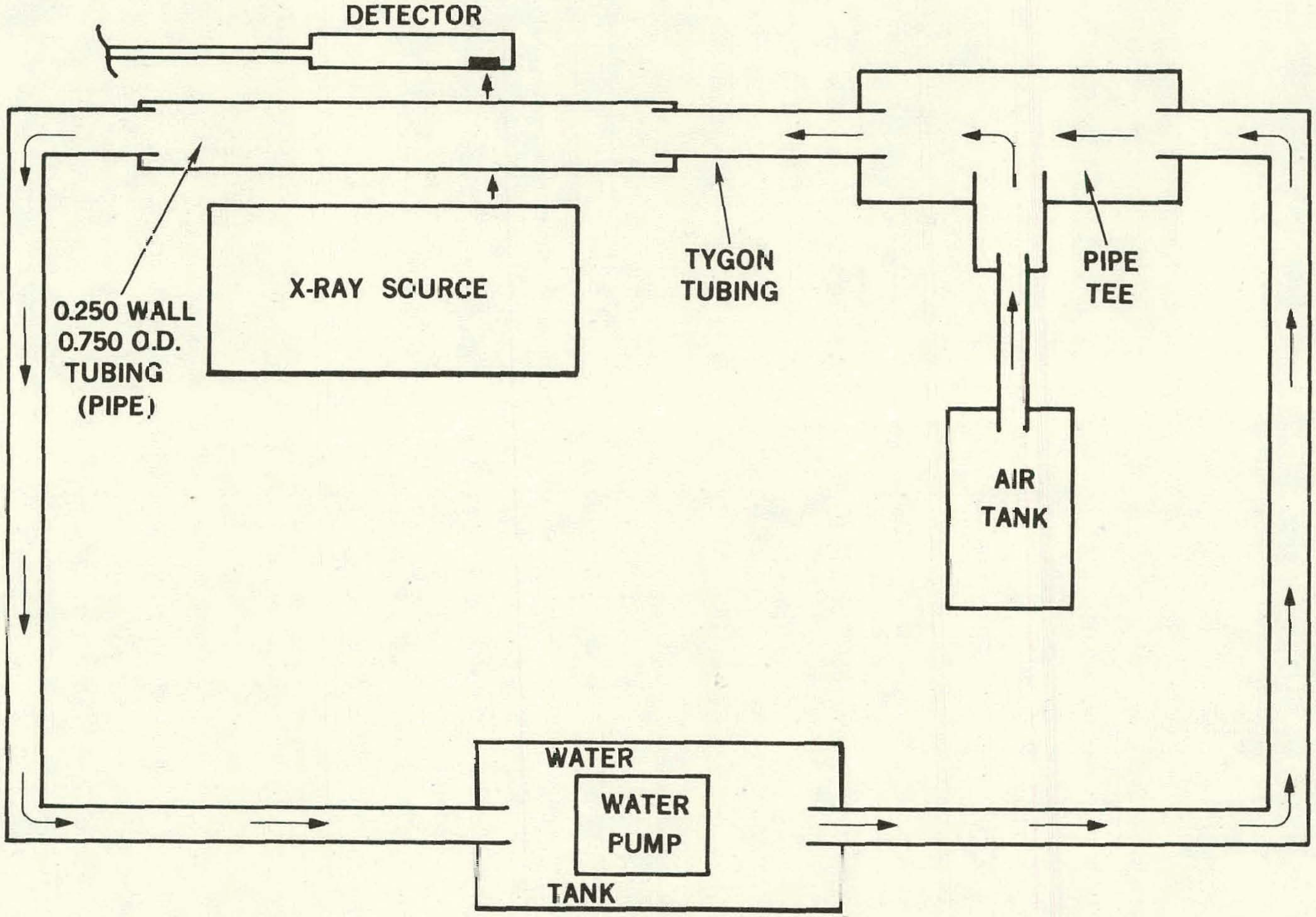


Figure 4 - Positive print of an X-ray showing the 3-phase system coal, oil, and gas.



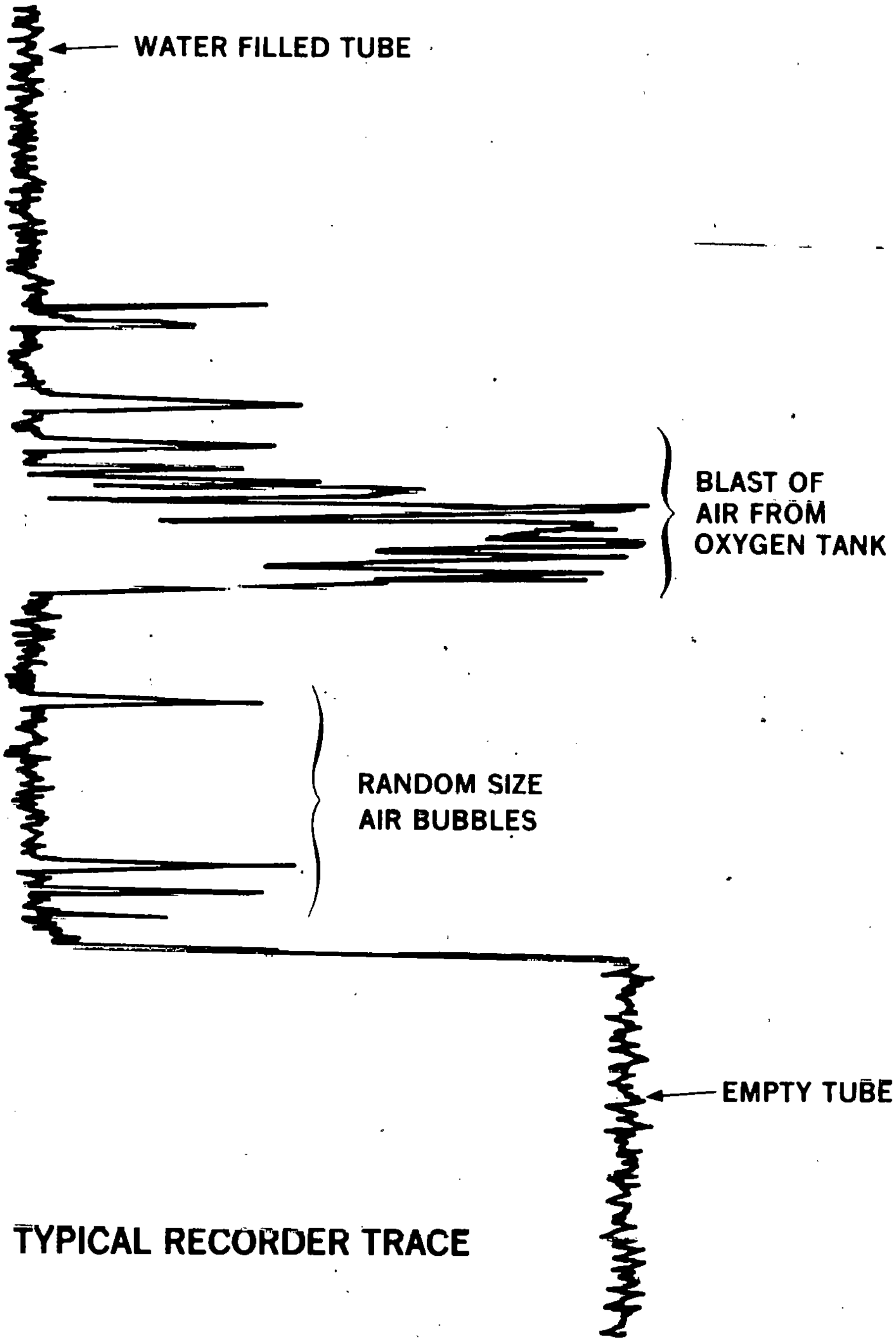
LINE DRAWING OF DXT SET-UP

Figure 6 shows data from the simulated experiment. The signal from the empty tube and that obtained when liquid is passed through the tube serve as base lines. Gas injected is observed as decreased density from the one-phase liquid system. The frequency of these bubbles (by counting) and the size (width at half-height) are calibrated to yield void volume of the system. In addition, flows (slug, froth, bubble) would be clearly distinguishable. This instrumentation is currently used in conjunction with a low pressure slurry loop for residence time/flow regime determination at Sandia Laboratories.

b) Phase boundaries and solid-liquid separation. The distillate bottoms from coal liquefaction processes contain large amounts of solids including organic and inorganic materials. The separation of the ash containing material can also be monitored by the use of a radiation gage in line with a collimated X-ray source. The density gradients of the liquid (low ash)/ solid (high ash) can be determined and plotted in real time, as described above. This may allow for direct process control in deashing systems. Initial experiments using this system were conducted at Sandia Laboratories and additional experiments are currently underway at West Virginia University.[6]

Summary

Several X-radiographic techniques have been applied to specific problem areas in coal liquefaction. The ultimate goal is the demonstration of applicability towards process monitoring. Deposits in lines and valves which result in blockages can be detected and the severity analyzed using film radiography and portable equipment. Erosion in the system can be identified and monitored using high energy equipment. Density variation and phase boundaries can be analyzed using film radiography, and/or by the use of a radiation gage. The technique employing the radiation gage provides real time analysis of dynamic systems. In addition, none of the applications requires modification of process equipment.



TYPICAL RECORDER TRACE

Figure 6

REFERENCES

1. B. Granoff, P. M. Baca, M. G. Thomas, G. T. Noles, "Chemical Studies on the Synthoil Process: Mineral Matter Effects," Sandia Laboratories Report SAND-78-1113, June 1978.

2. R. K. Traeger, T. C. Bickel, R. M. Curlee, "Preheater Studies in Coal Liquefaction," Sandia Laboratories Report SAND-79-0150, May 1979.

3. Private communication with Carmine Battista, Hydrocarbon Research, Inc.

4. R. M. Curlee, D. C. Hawn, "Design and Operation of a Bench Scale Coal Liquefaction System," Sandia Laboratories Report SAND-78-0837, July 1978.

5. Experiments were performed to obtain video-tape documentation at WMW and Associates, Van Nuyes, California, using a closed-circuit Vidicon Imaging System.

6. Experiments are being performed by J. Henry, West Virginia University, Morgantown, West Virginia.

COMPUTER-AIDED DATA ACQUISITION AND REPORTING AS USED IN THE H-COAL® DEVELOPMENT PROGRAM

Jeffrey L. Gendler and Paul R. Tabor
Hydrocarbon Research, Inc., Lawrenceville, NJ
A subsidiary of Dynalectron Corporation

INTRODUCTION

Until 1976, HRI's data acquisition and recording were accomplished by transcribing instrument readings on paper log sheets for all operating units, from 25-pound-per-day "bench scale" units to the 3-ton-per-day Process Development Unit. As the R & D industry moved away from tedious and costly manual data recording, HRI considered the many and varied methods of automatic data collection. The goal was to find a system which would provide this data-logging function, serve as a real-time process monitor and alarm, and provide on-line process calculations. Finding no such device on the market, HRI undertook the task of developing one from basic components.

STRUCTURE OF THE DASH^{TM} SYSTEM
(DATA ACQUISITION, STORAGE & HANDLING)

The host computer in HRI's system is a Sperry-Univac (formerly Varian) minicomputer in the V77 series, using the proprietary VORTEX® executive operating software. The machine is a 16-bit-per-word processor, configured by HRI with K-words of semiconductor memory, 20 megabytes of disc storage and a nine-track tape drive. In addition, a STATOS® printer/plotter (manufactured by Varian Graphics Co.) provides high-speed line printing and graphics. Low-speed KSR terminals are used for program editing and in the control room for data access.

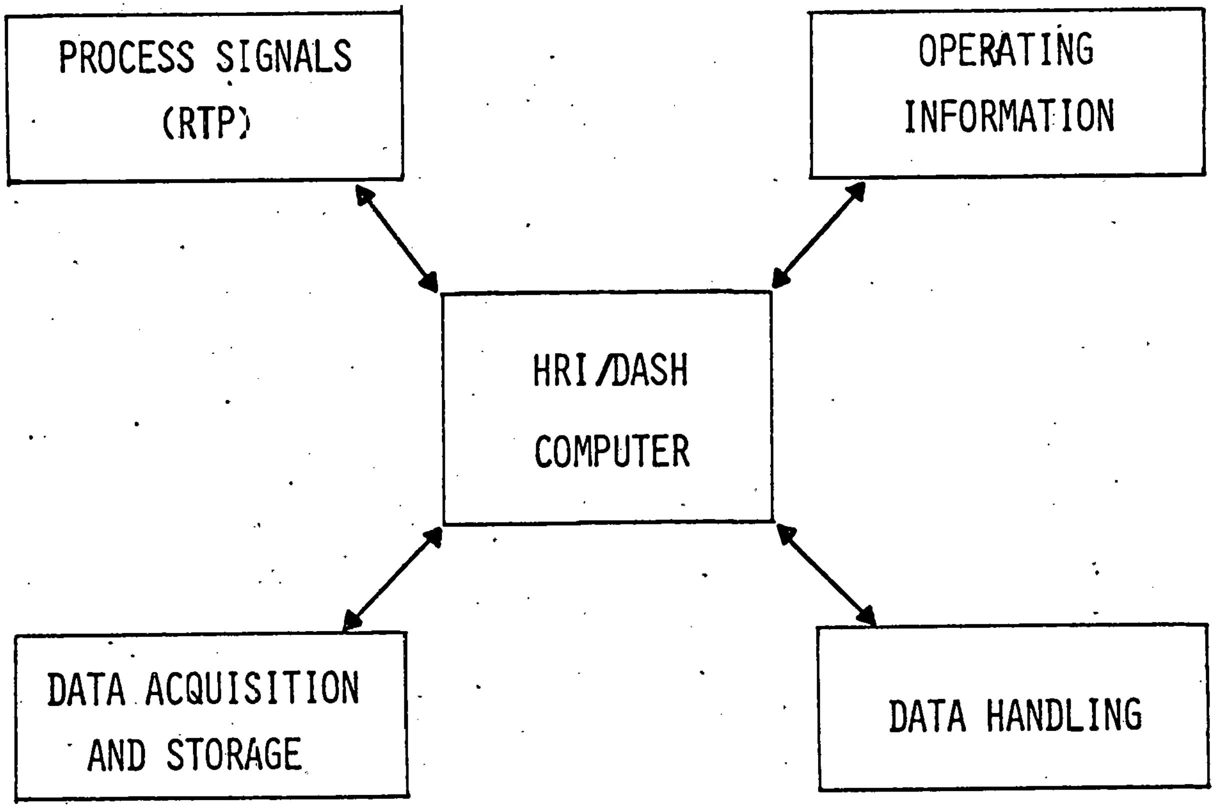
Process data is brought to the computer via limited-distance modem from the control room. HRI uses the RTP (Real-Time Processor) manufactured by Computer Products, Inc. Through a Wide-Range Analog Input System in the RTP, a variety of process signals may be monitored. For example, HRI monitors temperature (type "J" thermocouples), pressure (4-20mA transducers), digital load cells (16-bit BCD) and others. Each of these is converted to the analog-equivalent of a zero-to-ten volt signal, then transmitted in binary code to the computer.

The prioritized, multitasking environment of VORTEX allows modular programming of the DASH system. There are two core-resident programs and several other programs which are loaded as needed; all of these share a specified common memory area through which data values are passed. The two core-resident programs are:

1. DAP (Data Acquisition Processor) - This program reads a set of predefined control tables and uses their values to select active process data points in a specified order and read the current value of each into memory. Through another control table, incoming data values (in volts) are converted to engineering units, then stored on disc, in chronological order. Internal timers schedule data scans (typically once every two minutes), take averages on the hour, and call in data-handling programs at specified times.

2. ALM (Alarm Limit Monitor) - As each data point is read, its value is compared to two control-table values: an upper limit and a lower one. If either bound is exceeded, ALM takes two actions: First, a message is printed at the control room terminal giving the current point name and value, and the boundary value which was exceeded. Second, one of several programmable relay contacts is closed; it could, for example, ring an alarm bell.

DATA FLOW PATTERN



HRI DATA REPORTING PROGRAMS

While data acquisition is in progress, the data is made available to operating personnel on a "real-time" basis. That is, data is immediately available for evaluation by operators. Our engineers also use the process data, but their time-frame is somewhat different.

Generally, the engineers have to wait for a variety of data to become available. Because of the inherent time delay involved, we consider the engineering data as "post-period data processing". To aid our engineering staff, and to help generate customer reports, we have developed computer programs for both general and specific calculation needs.

For example, using the graphics capability of the computer and the STATOS printer/plotter, we are able to generate temperature/pressure profiles of our H-Coal® Reactor. These profiles show the entire unit at a single glance. Depending upon the location of the data (i.e., tape or disc), the diagrams can be printed in from 2 to 30 minutes. Some of these diagrams are printed on a daily basis while others are used only as a trouble shooting guide.

During routine operation of the test units, we generate daily mass balances as well as brief summaries of laboratory analyses. Since much of this data is reported to our clients, we have developed a computerized data base to speed up our reporting procedures.

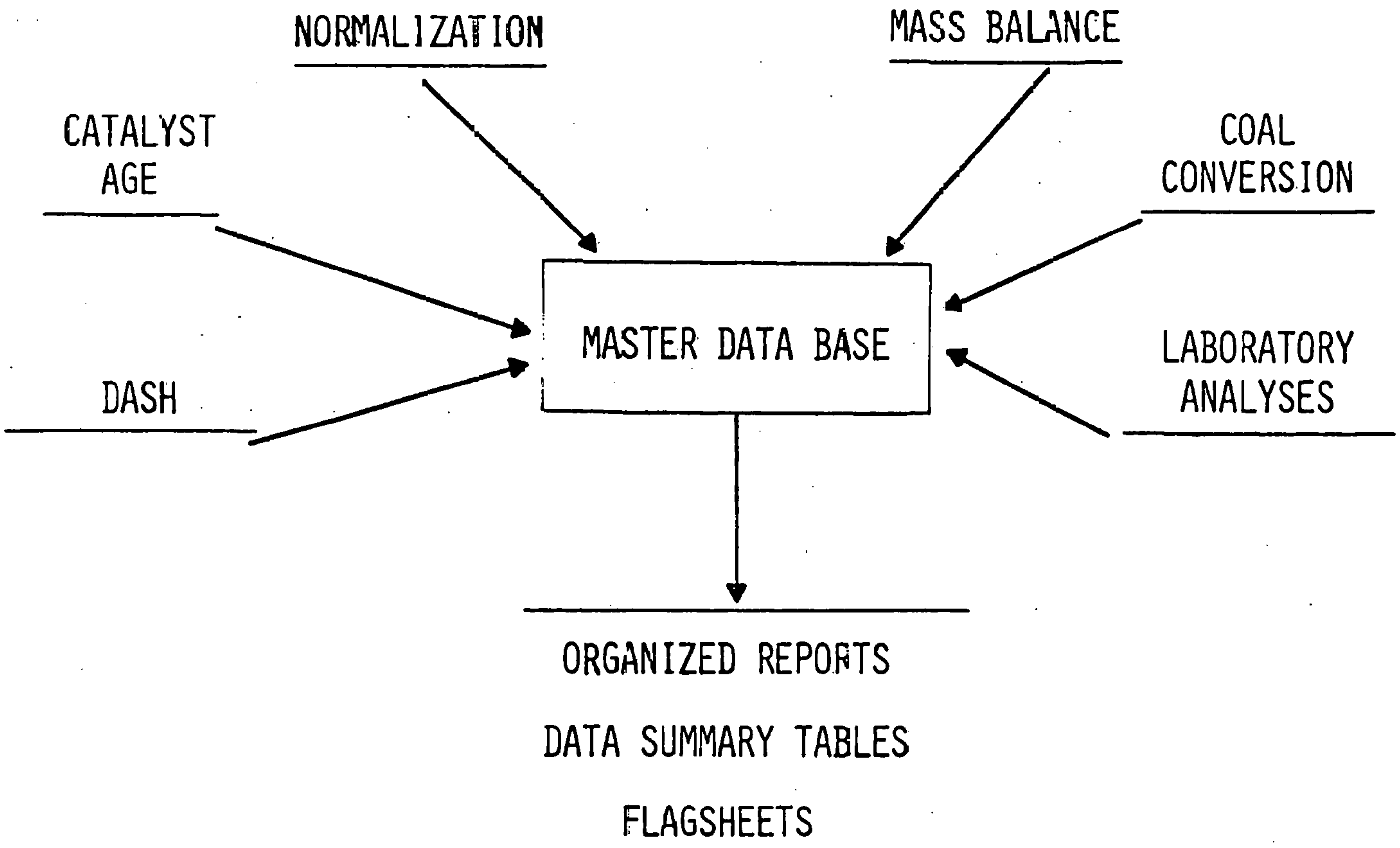
Because of the time lag in receiving different types of data, we immediately evaluate the data for day-to-day operations. This data is then saved for more comprehensive evaluation at some later date. Every program has a unique input data and its own reporting format. In addition, the data from the program is recorded on a reel of magnetic tape. To minimize possible errors and to maintain data security, every program records on its own reel of tape in a standard format. The tapes are corrected and updated as often as necessary.

After the data has been generated for a given day of operation, a merging program is used to blend the pertinent data into a master data base. This data base is also recorded on tape for permanent storage and for reporting purposes.

For reporting, the data for a given period is read from the data tape and printed in a data summary table. These summary reports can be printed as often as required. They can be used as a preliminary evaluation of data, a quick check for missing data, or as a final data table in our customer reports.

With our computerized reporting system, all PDU data is entered into the computer and can be used over and over. After the calculations are complete, and the last laboratory analysis is determined, we can generate data tables within 3-5 days. These tables are complete, descriptive, and ready for inclusion in a final report.

SYSTEMS DATA FLOW



HISTORY OF COMPUTER-AIDED DATA ACQUISITION AT HRI

In 1976, HRI installed a research-oriented computerized data acquisition system for its bench-scale and Process Development Units. This system was designed to monitor, acquire, and record process data from the experimental units and to issue reports based on that data. The system was first used on the H-Coal Process Development Unit (PDU) at the HRI R & D Center, and its functions were to:

- record PDU temperatures, pressures, and feed/product weights
- scan all process data up to 60 times per hour
- check each data point for out-of-defined-range status
- sound alarms and print status messages when necessary
- provide operators with current process data (on request)
- provide operators with time-averaged data (on request)
- give a daily report of averaged key operating conditions
- store all recorded data on tape for future access.

Once in operation, the system eliminated the need for operators to manually log process data; this saved thirty operator hours per unit-day. In addition, now that recorded data was on easily-accessed computer tape, the technical staff no longer had to handle paper log sheets and worry about filing and duplicating data sheets.

The on-line (real-time) system acquired and stored process data, as intended, on the H-Coal PDU: the next step was to organize, sort, and report the data in a useful manner. The engineering staff at HRI developed specialized reporting software to meet this need. HRI reporting and correlating programs:

- create a master data base for the duration of the run
- sort analytical laboratory data on input and generate appropriate reports
- sort batch filtration and distillation data on input and generate appropriate reports
- combine the real-time data with the above to generate a complete material balance

- store all of the above for end-of-run reports and data correlations

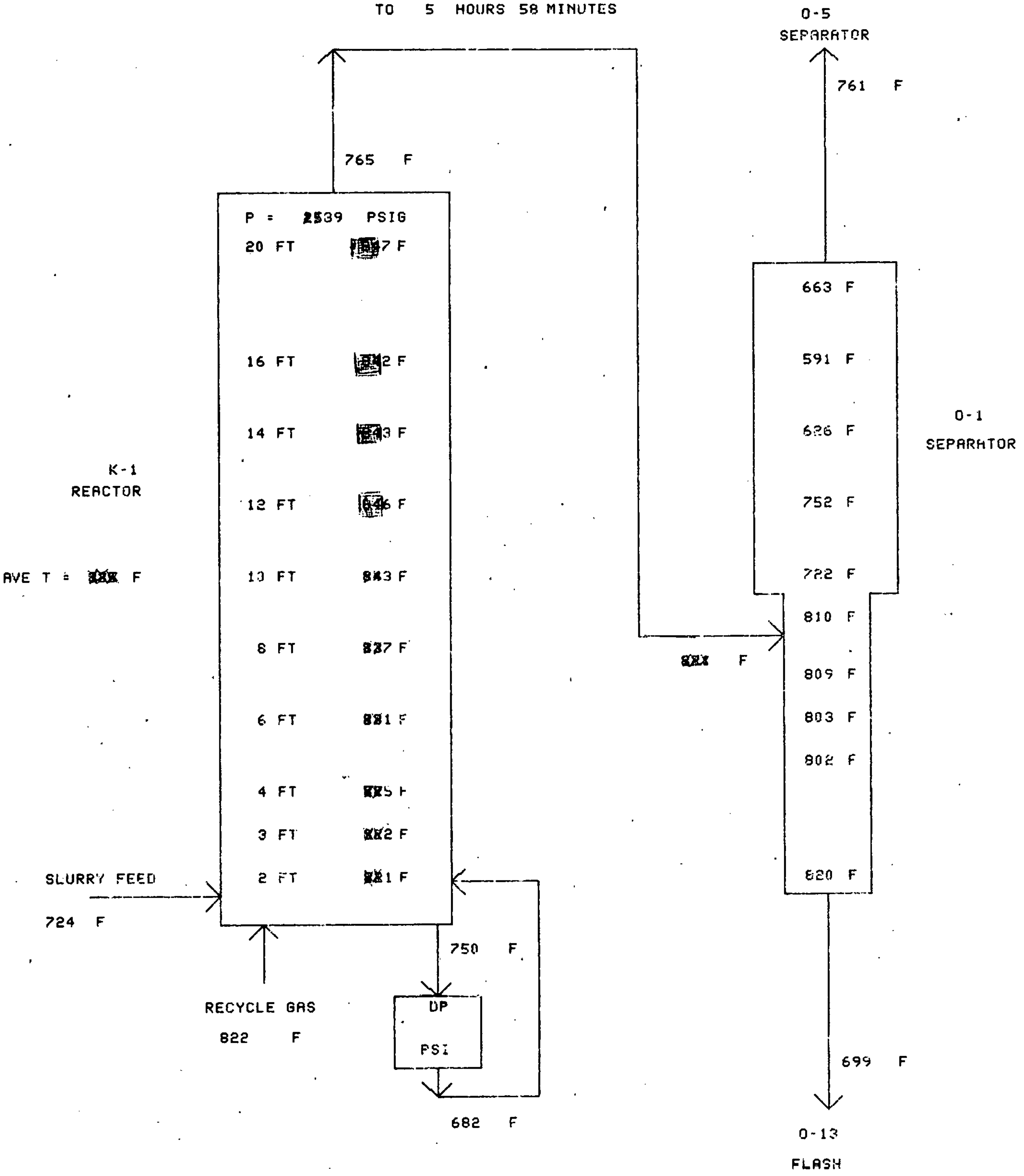
The same computer system is now also being used at the R & D Center on the Fast Fluid Bed Gasifier PDU and on H-Coal bench-scale units. The operating programs for each unit vary; for example, the FFB gasifier program module does not sound out-of-range alarm, but it does print a process data summary every eight hours (not done on the H-Coal PDU).

HRI is continuously improving its in-house data acquisition system. Through HRI and Sperry-Univac, specialized hardware and software can be designed for other pilot plant or bench-scale units. These systems can record data, monitor real-time operations and generate concise reports.

H-COAL PDU
REACTOR CONDITIONS

RUN 130 - 87

DATE 6 / 27 / 79
PERIOD 2 B
FROM 18 HOURS 0 MINUTES
TO 5 HOURS 58 MINUTES



COAL PREPARATION AND FLOW CONTROL FOR THE MHD FACILITY AT TULLAHOMA, TENNESSEE

A. Ziobrowski and E. Lazor
Babcock & Wilcox Company
Research and Development Division
Alliance, Ohio

SUMMARY

In November, 1975, the Babcock & Wilcox Company (B&W) contracted with the University of Tennessee to supply auxiliary components and technical support for the U. S. Department of Energy MHD Facility at Tullahoma, Tennessee.* Among the components being supplied by B&W is a coal and seed (potassium carbonate or potassium sulfate) preparation and injection system. This system has been designed to inject up to 3.3 tons of coal and seed per hour for an unlimited period of time and up to 9.2 tons of coal and seed per hour for 2 hours to a combustor operating at pressures up to 120 psia. The coal and seed can be injected into the combustor through single or multiple feed points.

Installation of the system is now complete. Tests are currently being performed to check out the components and characterize the system. Startup of the system and its integration into the MHD facility are expected in late 1979 or early 1980.

INTRODUCTION

Techniques for pneumatically conveying solids from one location to another have been reliably practiced for many decades. However, the emergence of new energy-producing technologies has necessitated the development of systems capable of delivering crushed or pulverized coal in a steady, non-pulsating flow to processes operating at high pressures. Coal gasification and pressurized fluidized bed combustion are two such processes.

---

*Sponsored by D.O.E. Contract No. EX-76-C-01-1760.

The successful commercial development of a coal-fired, combined cycle MHD/steam system for generating electricity also requires the development of such a coal feed system. Combustion pressures of approximately 8 atmospheres are anticipated, and pulsations in the feed rate to the combustor could significantly reduce efficiency. In addition, as little "cold" carrier gas as possible should be injected into the process with the coal. Reducing the amount of this carrier gas increases system efficiency by allowing higher combustion temperatures for a fixed coal to air ratio. It also may reduce capital and operating costs by lowering the compressed gas requirements of the system.

The Babcock & Wilcox Company (B&W) has designed and fabricated systems for conveying pulverized and crushed coal for many years. Therefore, when selected by the Department of Energy (DOE) to design a pulverized coal feed system for its MHD Facility in Tullahoma, Tennessee, B&W could lean heavily on its experience in this area. The following sections first review the company's background in this area and then describe the specific system being supplied to the Department of Energy.

TRANSPORTING PULVERIZED COAL AT ELEVATED PRESSURES: B&W EXPERIENCE

B&W began evaluating systems that could be used to continuously inject pulverized coal into equipment operating at high pressures in the early 1950's. At that time the specific application under consideration was the feeding of coal into industrial blast furnaces. Tests to determine the transportability of pulverized coal at various coal rates, velocities and pressures up to 40 psig were conducted at the company's Alliance Research Center in Alliance, Ohio. This accumulated design data and experience led to the design and construction of the pulverized coal injection system that was later installed on Armco Steel's Bellefonte blast furnace at Ashland, Kentucky. Placed into commercial service in 1966, the system continues to inject up to 25 tons of pulverized coal an hour through the furnace's 16 feed points.

In June 1973, a larger second-generation pulverized coal injection system was put into service on Armco's Amanda blast furnace. This system, the largest in commercial operation in the United States, feeds up to 33 tons of pulverized coal an hour to the furnace through 24 feed points. Operating at furnace pressures between 25 and 30 psig, this injection system has experienced virtually 100% availability since its installation.

The installations at both the Bellefonte and the Amanda plants are dilute-phase transport systems, meaning the coal-gas mixture has a density of less than 4 lb/ft^3. B&W's developmental work over the years has concentrated on the design of such systems. Simultaneously, a significant amount of information was being gathered on the pneumatic transport of solids at much higher solid-to-gas ratios and densities (also known as dense-phase transport). The combined experience of our dense-phase studies and the more practical commercial applications of the dilute-phase systems at Bellefonte and Amanda has been applied to the coal and seed injection system being supplied to the Department of Energy.

MHD FACILITY DESIGN CONSIDERATIONS

At the beginning of the contract, B&W and the University of Tennessee, the prime contractor, agreed that this system should represent as nearly as possible an actual coal and seed injection system that might be used on a commercial MHD power generating unit. Because the performance of the MHD generator is so closely dependent on the performance of the fuel injection system, it was decided that this system should not be considered as merely a piece of apparatus to support the testing but as a tool for developing and continually improving the injection system.

To implement this design philosophy, the following performance criteria were established:

- Raw coal and seed would be ground to a sizing of 70% through 200 mesh and dried. This represents the typical sizing used by today's conventional coal-fired boilers.

- Coal and seed would be blended before injection into the combustor, thus eliminating the need for two separate injection systems. In addition, the proportion of seed to coal in the mixture should be controllable and variable for developmental purposes.
- The coal and seed would be fed to a combustor operating at pressures up to 6 atmospheres at a mixture flowrate of 3.3 tons per hour for 100 hours of continuous operation.
- The coal and seed would also be fed to a combustor operating at pressures up to 8 atmospheres at a mixture flowrate of 9.2 tons per hour for 2 hours of continuous operation.
- The coal and seed would be injected into combustors of various designs through single or multiple feed ports.
- Air would be used as the transport medium to avoid the need for inert gas generators. The amount of air to be injected into the combustor with the coal and seed would also be minimized to improve combustor performance.
- Combustion would be initiated by injection of coal and seed into the combustor at as low a rate as possible, and gradually the rate would be increased to the nominal flowrate. This should protect ceramics in the flow train against excessive thermal shock. The system would be additionally capable of an instantaneous start at the nominal steady-state flowrate, if necessary.

DOE MHD FACILITY COAL AND SEED INJECTION SYSTEM

The MHD coal and seed injection system can be divided into two subsystems (see Figures 1 and 2). The Coal and Seed Preparation Subsystem blends the raw coal and seed as it is pulverized and dried. The Coal and Seed Injection Subsystem then injects the pulverized coal and seed into the combustor.

COAL AND SEED PREPARATION

The Coal and Seed Preparation Subsystem consists of relatively conventional bin-type coal pulverizing equipment. It deviates from conventional applications in that seed is blended with the coal in the pulverizer. The subsystem can supply approximately 4 tons per hour of the pulverized coal and seed mixture. The proportions of pulverized coal and seed can be varied to any desired level.

The raw coal and seed are manually loaded into their respective hoppers. Screw conveyors and a bucket elevator move the raw coal and seed from the hoppers into their respective storage tanks. The raw coal hopper, screw conveyor and bucket elevator were supplied by Webster Manufacturing; the seed hopper and screw conveyor were supplied by Clemons. B&W designed both storage tanks with the raw coal tank having a 30-ton capacity and the seed tank a 3-ton capacity.

The storage tanks discharge their contents into their respective weigh feeders which move the coal and seed from the storage tanks to the inlet of the pulverizer. The speed of the coal weigh feeder, supplied by the Stock Equipment Company, is automatically regulated to maintain the recommended level in the pulverizer. The speed of the seed weigh feeder, supplied by the Merrick Scale Company, is controlled by a signal from the coal weigh feeder so that the ratio of seed to coal entering the pulverizer remains at a pre-set value.

The B&W E-35 pulverizer grinds the mixture of coal and seed until the particles are fine enough to be swept out of the pulverizer by an air stream from a Carl Mayer indirect fired air heater. At the pulverizer's rated air flow rate, the fineness will be 70% through 200 mesh. This air serves three distinct purposes: (1) It controls the particle size and flowrate of the mixture leaving the pulverizer; (2) it transports the mixture from the pulverizer to the bag filter; and (3) it dries the mixture.

The heated air carries the coal and seed mixture to a Pedcon bag filter where the mixture is separated from the air. The air itself is discharged to the atmosphere while the mixture is fed through a rotary valve to one or both of the two pulverized coal and seed reservoir tanks.

COAL AND SEED INJECTION

The coal and seed injection subsystem is of the lockhopper type. Its components include two 5-ton capacity reservoir tanks elevated above a 10-ton capacity feed tank and their associated valves, piping and instrumentation. The three tanks were designed by B&W.

The two reservoir tanks are operated cyclically as shown in Figure 3. While one reservoir tank is being filled, the other is pressurized, its contents are transferred to the feed tank, and then it is depressurized.

Pressurizing the reservoir tank to the same level as the feed tank before transferring the coal and seed mixture avoids disturbing the feed tank pressure as the mixture passes from the reservoir tank. Such a disturbance in feed tank pressure would adversely affect the flowrate to the combustor. Pressurizing air enters the reservoir tank through eight distributing nozzles that protrude through the wall of the vessel into the coal and seed mixture. The heat of pressurization is partially absorbed by the mixture, thereby reducing the increase in air temperature that would otherwise occur. When the reservoir tank pressure reaches that of the feed tank, a pressure equalizing line between the two opens to ensure that the pressure in both tanks remains the same during the transfer.

Once pressure equalization is complete, fluidizing air is introduced at the discharge of the reservoir tank. A bleed valve on the reservoir tank is also opened to prevent the internal pressure from rising as a result of the additional fluidizing air input. The valve in the transfer line between the reservoir tank and the feed tank is opened and the mixture is gravity-fed to the feed tank.

After transfer is complete, the valves in the transfer line and pressure equalizing line are closed, fluidizing air in the reservoir tank is stopped, and the tank is depressurized. The reservoir tank is then recharged while the other is pressurized and its contents transferred to the feed tank, thereby completing the cycle.

The differential pressure between the feed tank and the combustor acts as the driving force for injecting the pulverized coal and seed into the combustor. Feed tank pressure is adjusted to maintain the differential pressure corresponding to the desired flowrate. Such adjustments can be performed manually, to change flowrate, for example, or can be automatically adjusted to a set point by the system controls.

The spacial density of the mixture flowing from the feed tank must be carefully controlled since flow stability is extremely density dependent. Small amounts of air injected into the bottom of the feed tank provide the coal and seed with mobility. During certain modes of operation, particularly at low flowrates, additional dilution of the coal and seed stream is required. In these situations, air is injected directly into the stream after it leaves the feed tank through a specially designed section of transport pipe known as the air pickup section.

The transport pipe is approximately 100 feet in length. Since its diameter is flowrate dependent, two separate transport piping arrangements were required to span the flowrate ranges requested.

A 3/4-inch schedule 80 transport pipe was selected for the nominal injection flowrate of 3.3 tons per hour. Stable injection flowrates can thus be maintained over a range commencing at a minimum of 0.2 tons per hour with a spacial density of 0.3 lb/ft^3 up to a maximum of 4 tons per hour with a spacial density of 30 lb/ft^3. A double, extra heavy 1-1/2 inch pipe was chosen for the nominal flowrate of 9.2 tons per hour. Injection rates ranging from 0.5 tons per hour with a density of 0.3 lb/ft^3 to 11.5 tons per hour with a density of 30 lb/ft^3 can be kept stable with this size pipe. In addition, the system is easily adaptable to other pipe sizes should different flowrate ranges be desired in the future.

For multi-feed combustors a flow distributor has been provided. Located in the transport pipe just upstream of the combustor, the distributor divides a single stream of coal and seed into four equal streams, each supplying a combustor feed point. If more than four feed points are required, these four streams can each be subdivided.

CONTROLS AND INSTRUMENTATION

The controls used in the coal and seed preparation subsystem are, like the equipment itself, also relatively conventional. Both screw feeders and the bucket elevator are activated by demand signals from level detectors in the seed and raw coal storage tanks. The raw coal weigh feeder receives its control signal from a level measurement device in the pulverizer. Seed weigh feeder flow control is slaved to the output of the coal weigh feeder, with the ratio of the two flowrates being established in advance by the operator.

The flowrate of the air from the forced draft fan, through the air heater and the pulverizer to the bag filter is controlled by a damper at the air inlet to the pulverizer. The damper is electropneumatically controlled, receiving its input signal from a flow element mounted in the line just upstream of the damper. Air temperature is automatically adjusted to maintain a pulverizer outlet temperature of 150°F.

The Coal and Seed Injection System is controlled by an Allen Bradley Programmable Controller that operates in either a manual or an automatic mode. The operator has the option of manually opening and closing any of the subsystems' 29 valves with individual front panel switches. Startup and shutdown of the system, for instance, are performed in the manual mode.

In the automatic mode, the programmable controller opens and closes the various valves in a programed time sequence that is augmented by a series of process signal interlocks. This interlock feature constantly interrogates valve limit switches, system pressures and temperatures, and load cell readouts to verify the proper performance of the system.

Lights on the control panel that are energized by limit switches provide the operator with a graphic display of the status of each valve (open or closed).

CURRENT STATUS

The Coal and Seed Injection System at the Tullahoma MHD Facility is now in place. Instrument and control wiring has been completed, power has been connected to the system, and temporary instrument air applied. The program for the Coal Transport Programmable Logic Controller has been written and debugged. All valves have been sequenced by the automatic mode program and the results observed on the limit switch actuated graphic display.

In conclusion, we feel the tests, soon to begin, will show that this is an adequate system for this new technology--MHD. The system designed uses some tried and proven coal handling technology. These have been combined with some younger technologies such as dense phase coal transport and the programmable logic controller to achieve the design requirements.

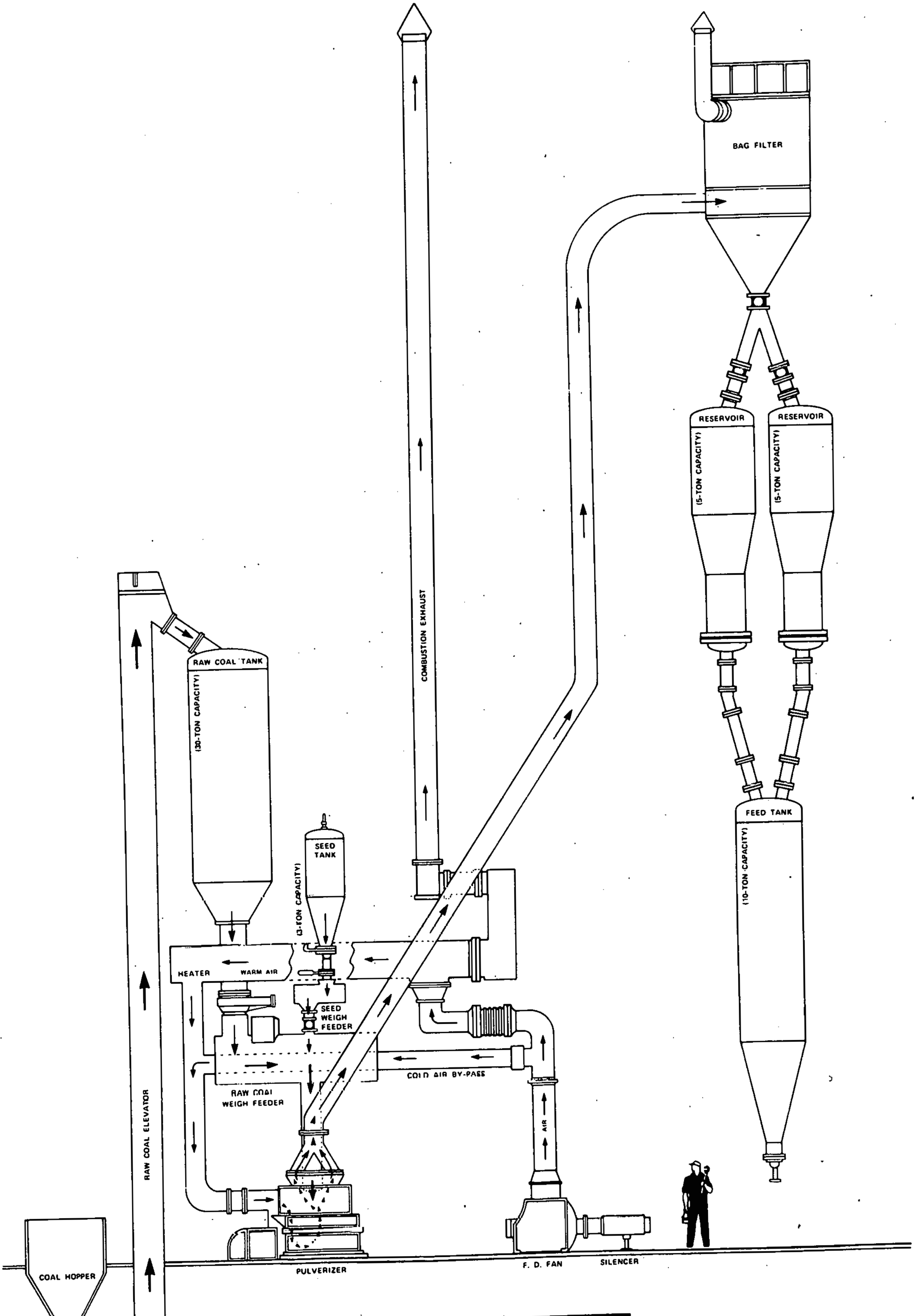
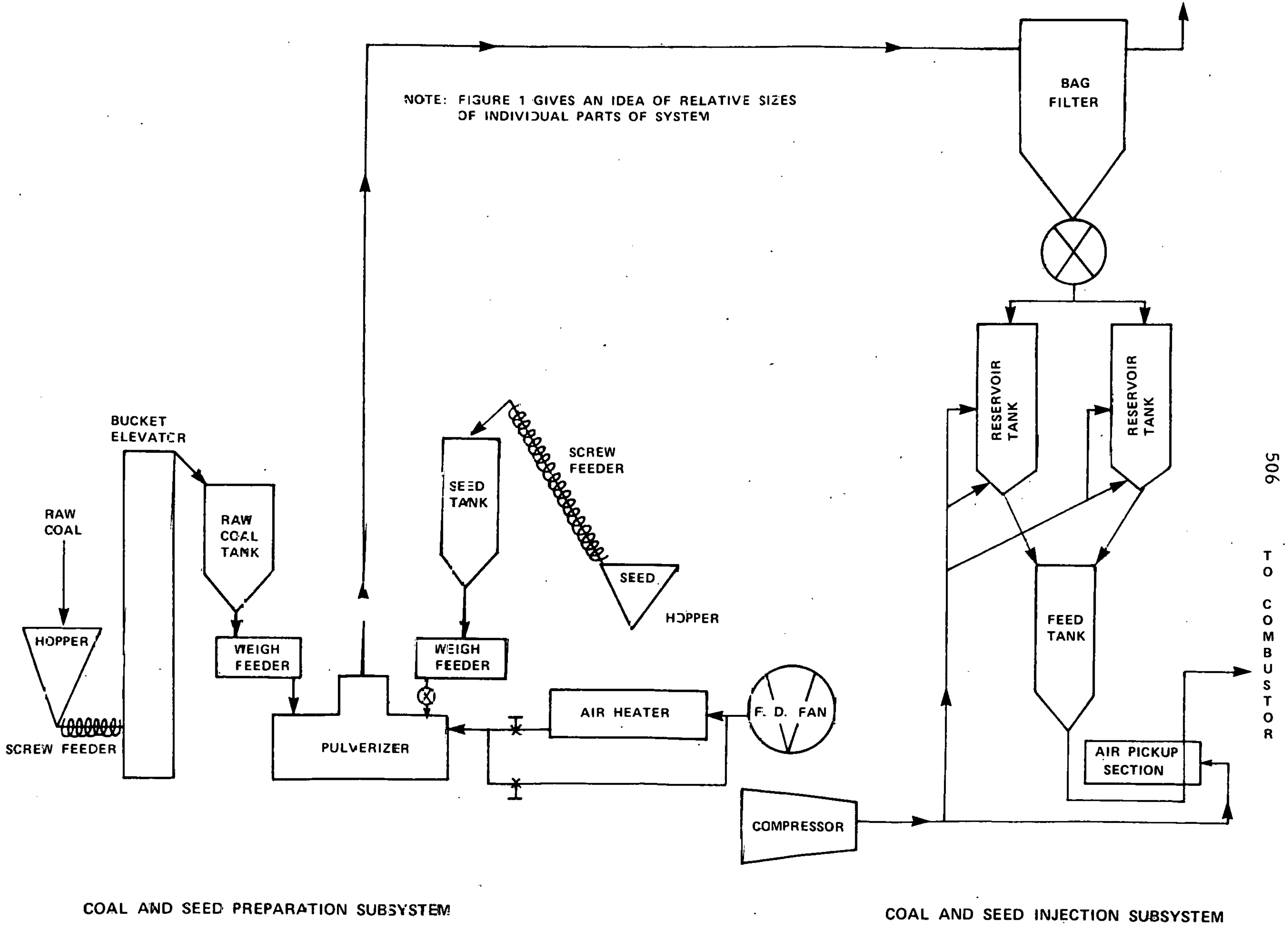


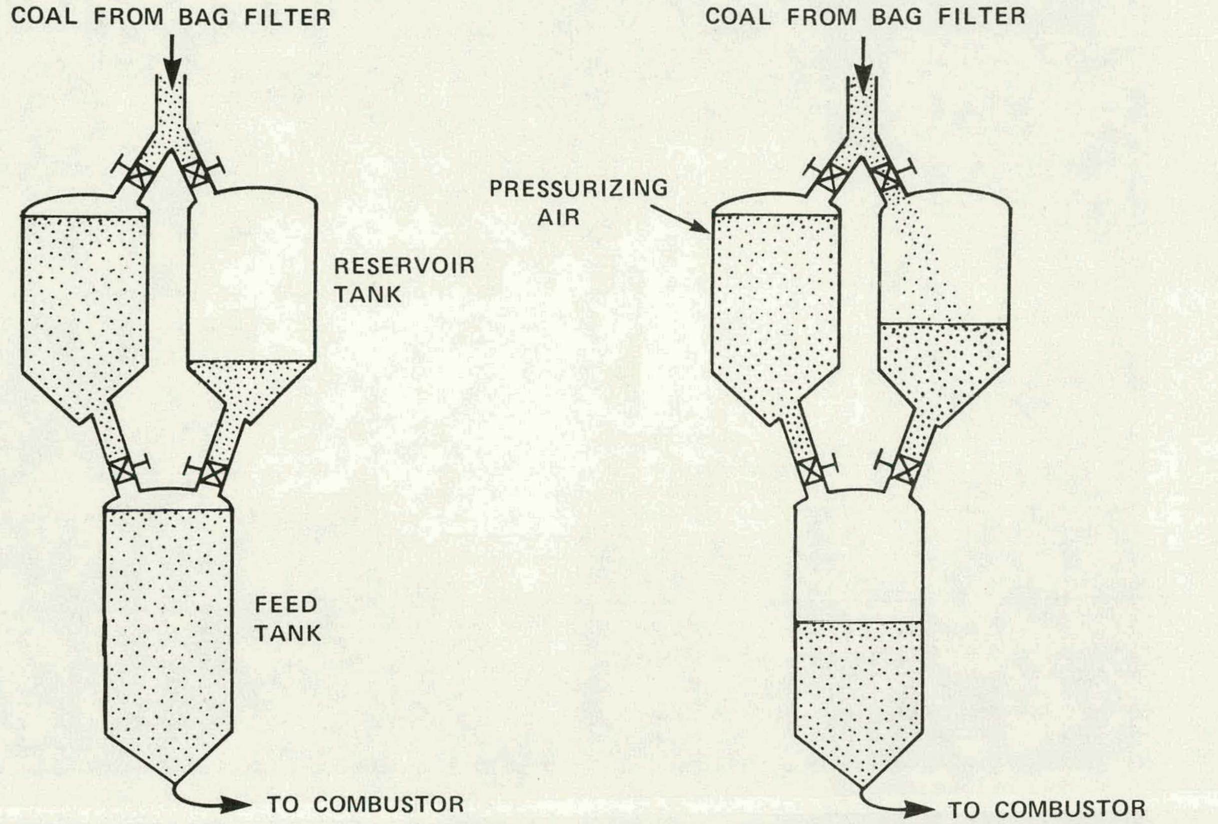
FIGURE 1 • COAL AND SEED HANDLING SYSTEM

FIGURE 2. COAL AND SEED HANDLING SYSTEM



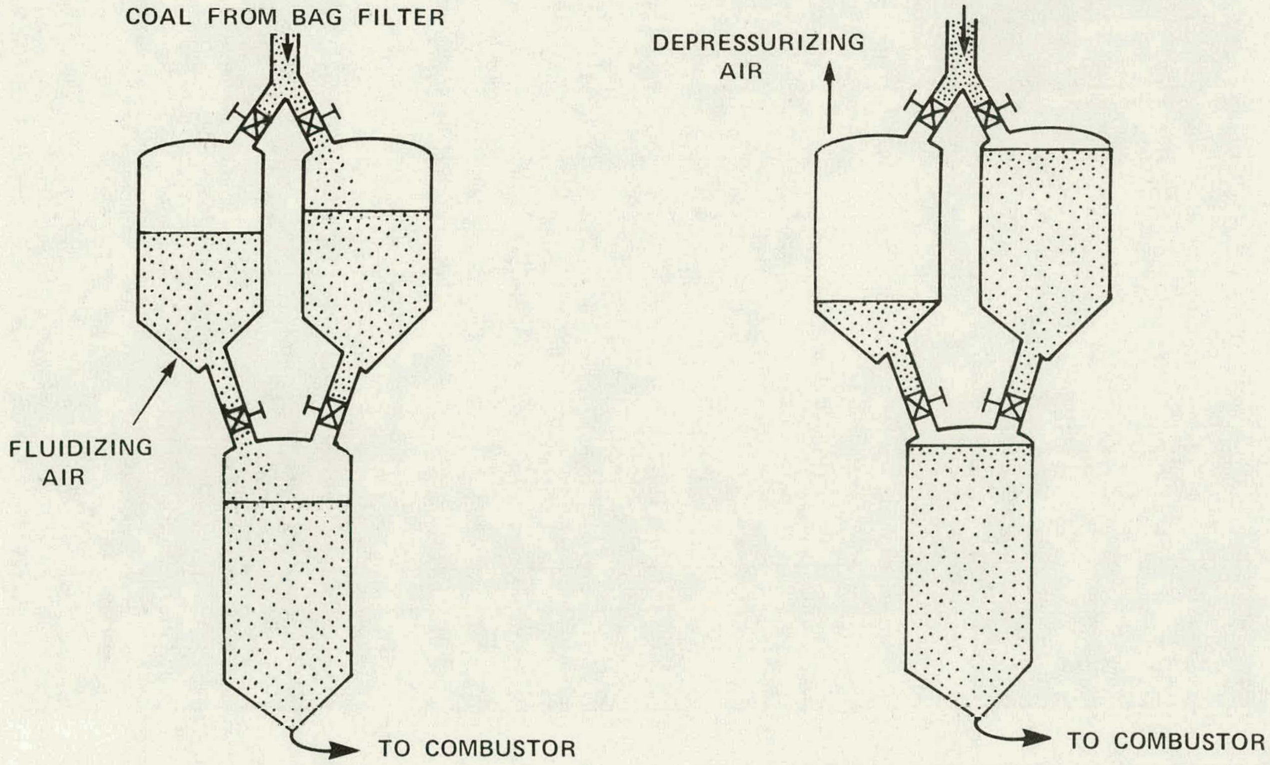
NOTE: FIGURE 1 GIVES AN IDEA OF RELATIVE SIZES OF INDIVIDUAL PARTS OF SYSTEM

FIGURE 3 CYCLICAL OPERATION OF THE COAL AND SEED RESERVOIR TANKS



A. BOTH RESERVOIR TANKS ARE AT ATMOSPHERIC PRESSURE. LEFT TANK IS FULL, RIGHT TANK REQUIRES RECHARGING

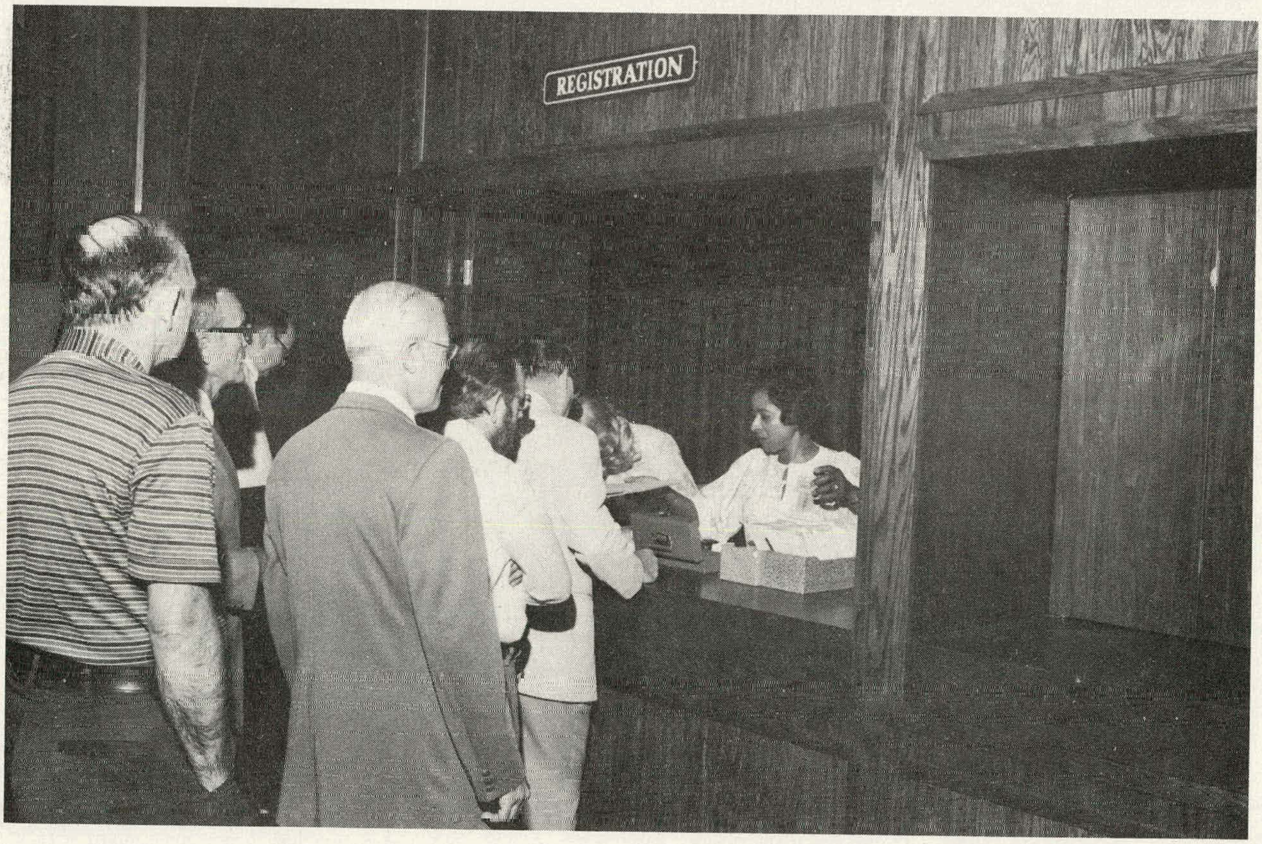
B. LEFT RESERVOIR TANK IS PRESSURIZED TO SAME LEVEL AS FEED TANK. REFILLING OF THE RIGHT TANK BEGINS

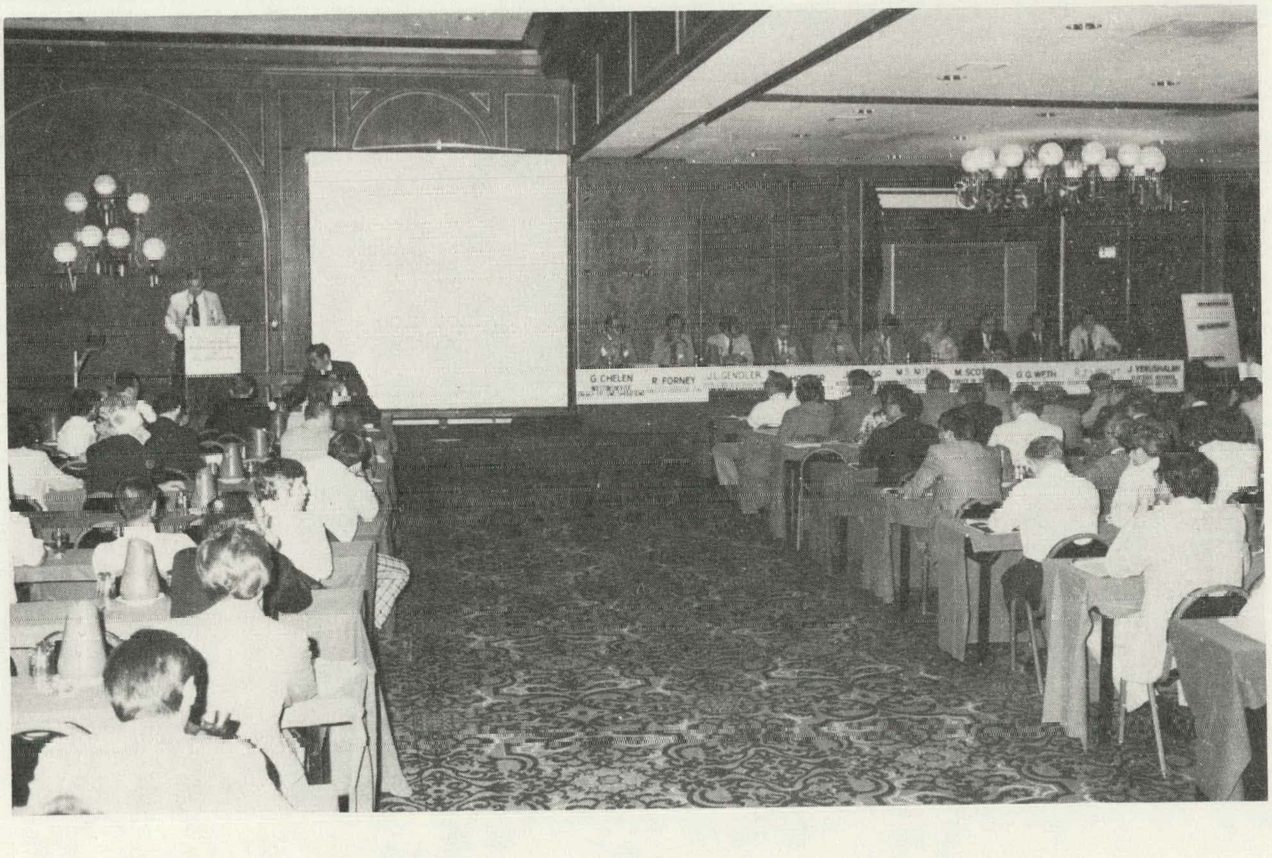


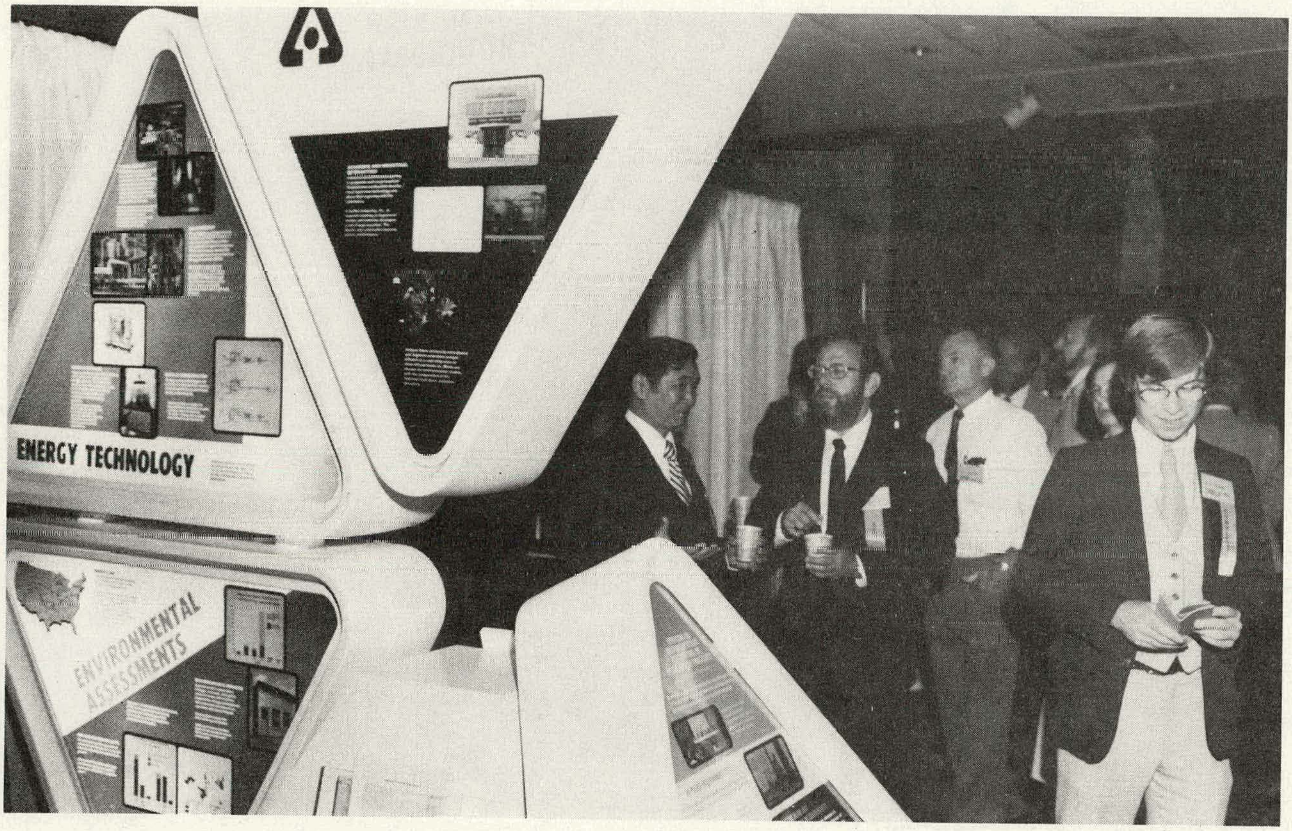
C. COAL IN LEFT TANK IS FLUIDIZED AND TRANSFERRED INTO FEED TANK. REFILLING OF RIGHT TANK CONTINUES

D. AFTER COAL TRANSFER IS COMPLETE, THE LEFT TANK IS DEPRESSURIZED TO ALLOW REFILLING. RIGHT TANK IS FULL AND READY TO REPLENISH COAL IN FEED TANK.


1979 SYMPOSIUM ON
INSTRUMENTATION AND CONTROL
FOR
FOSSIL ENERGY PROCESSES
RECEPTION
SUNDAY AUGUST 19
6:00 P.M. 10:00 P.M.
GRAND BALLROOM (A.B.C.)


REGISTRATION


G CHELEN
R FORNEY
J.L. GENDLER
J YERUSHALMY


ENERGY TECHNOLOGY
ENVIRONMENTAL ASSESSMENTS

List of Attendees

J. A. Armstrong
Denver Research Inst., U. Denver
T. Atwood
Office of Fossil Energy, USDOE
W. D. Bachalo
Spectron Development Labs., Costa Mesa, Calif.
R. J. Ballenger
Rockwell International, Canoga Park
P. M. Barker
Rockwell International, Canoga Park
M. J. Barrody
Catalytic, Inc., Wilsonville, Ala.
W. E. Baucum, Jr.
U. Tennessee Space Institute, Tullahoma
P. Baumeister
Aerojet, Azusa
F. H. Bekker
Koppers Company, Inc., Pittsburgh
C. E. Berthold
Hazen Research, Inc., Golden, Colo.
N. T. Bolt
British Gas Corp., London, England
D. L. Bonk
Babcock & Wilcox, Alliance, Ohio
R. T. Boos
Bethlehem Steel Corp., Bethlehem
H. Bozorgmanesh
Science Applications, Inc., Sunnyvale
N. C. Bradley
Union Carbide Corp., Oak Ridge
T. R. Bump
Argonne National Lab.
L. E. Burkhart
Ames Lab.
G. W. Burns
National Bureau of Standards, Washington
C. W. Busch
Spectron Development Labs., Costa Mesa, Calif.
A. E. Cannon
Westran Corp., Santa Ana
C. T. Carroll
Foster Wheeler Energy Corp., Livingston, N. J.
T. X. Carroll
E. I. duPont de Nemours and Co., Wilmington
G. M. Caton
Oak Ridge National Lab.
R. J. Cerar
Pittsburgh Energy Technology Center, USDOE
H. Chang
Argonne National Lab.
G. J. Chelen
Westinghouse Electric Corp., Madison, Pa.

- H. A. Clayton
  - Phillips Petroleum Co., Bartlesville
- C. O. Cogburn
  - U. Arkansas
- R. D. Crabtree
  - General Atomic Co.
- H. M. Crawford
  - Exxon Research & Engineering Co., Florham Park, N. J.
- C. T. Crowe
  - Washington State U.
- E. Cuellar
  - Lawrence Berkeley Lab.
- R. L. Currie
  - Babcock & Wilcox Co., Lynchburg
- L. R. Dates
  - Argonne National Lab.
- H. Deich
  - MDH Industries, Inc., Monrovia, Calif.
- F. E. Diebold
  - Montana College of Mineral Science and Technology, Butte
- W. M. Dillow
  - Gulf Science & Technology Co., Houston
- G. I. Doering
  - Measurex Corp., Cupertino, Calif.
- R. W. Doering
  - Argonne National Lab.
- R. E. Dragoo
  - Stearns-Roger Engineering Corp., Denver
- B. L. Draper
  - Sandia Labs., Albuquerque
- R. L. Druva
  - Stearns-Roger, Inc., Denver
- R. M. Dryden
  - Gulf Mineral Resources Co., Denver
- A. K. Dubberly
  - Cameron Engineers, Denver
- R. H. Duckstein
  - Gulf Research & Development Co., Pittsburgh
- M. D. Durham
  - Denver Research Inst., U. Denver
- D. Earnshaw
  - Laramie Energy Technology Center, USDOE
- R. M. Eccles
  - Exxon Research & Engineering Co., Florham Park, N. J.
- F. T. Finch
  - Los Alamos Scientific Lab.
- L. E. Fleming
  - Exxon Co., Baton Rouge
- F. L. Fletcher
  - Rockwell International, Canoga Park
- F. Fonzi
  - Fonzi & Associates, Cedar Hill, Tex.
- R. Forney
  - Colorado School of Mines, Golden

R. W. Forsythe
Illinois Coal Gasification Group, Chicago
F. D. Freeburn
Morgantown Energy Technology Center, USDOE
W. Fuchs
Pittsburgh Energy Technology Center, USDOE
J. L. Gendler
Hydrocarbon Research, Inc., Lawrenceville, N. J.
R. J. Gendreau
Stone & Webster Engineering Co., Boston
V. A. Giroux
Phillips Petroleum Co., Bartlesville
T. Gozani
Science Applications, Inc., Palo Alto
E. F. Groh
Argonne National Lab.
D. R. Hajicek
Grand Forks Energy Technology Center, USDOE
R. M. Hamberg
TRW, Redondo Beach
R. A. Hammond
Boeing Computer Services, Bellevue, Wash.
C. Harper
Consolidated Controls Corp., El Segundo
W. P. Harrington
Stearns-Roger Engineering Corp., Denver
W. H. Hartwig
U. Texas at Atusin
C. L. Herzenberg
Argonne National Lab.
G. R. Hill
U. Utah
M. L. Honer
TOSCO Corp., Golden
B. R. Hoover
ARMCO, Inc., Middletown, Ohio
C. G. Houser
Phillips Petroleum Co., Homer City, Pa.
M. J. Howe
Leeds & Northrup, North Wales, Pa.
J. S. Hubacher
TRW Energy Systems Group, McLean, Va.
D. E. Hull
Phillips Petroleum Co., Homer City, Pa.
D. E. Hyatt
Hazen Research, Inc., Golden
J. Z. Inskeep
Jet Propulsion Lab.
D. H. Jaeger
WOP/SDC, Los Angeles
J. E. Janssen
Honeywell, Inc., Minneapolis
L. A. Jeffers
Babcock & Wilcox Co., Alliance, Ohio

D. T. Johnson
TOSCO Corp., Golden
D. G. Jones
Radian Corp., Pasadena
H. T. Jones
Office of Fossil Energy, USDOE
A. A. Jonke
Argonne National Lab.
H. Kaplan
Barnes Engineering Co., Stamford, Conn.
H. B. Karplus
Argonne National Lab.
N. L. Kautsky
Stearns-Roger, Inc., Denver
K. Kawatra
Michigan Technological U.
D. M. Kelly
Stearns-Roger, Inc., Homer City, Pa.
F. G. King,
Howard U.
L. W. Kirsch
Argonne National Lab.
P. H. Lafave
Combustion Engineering, Inc., Windsor
R. V. Laney
Argonne National Lab.
R. C. LaSell
Rosemount, Minneapolis
T. K. Lau
Office of Fossil Energy, USDOE
E. W. Lazor
Babcock & Wilcox Co., Alliance, Ohio
B. S. Lee
Inst. of Gas Technology, Chicago
J. W. Lee
The Bendix Corp., Lewisburg, W. Va.
L. G. LeSage
Argonne National Lab.
W. H. Levers
Standard Oil Co. of California, San Francisco
D. W. Lewis
U. Virginia
R. D. Litt
Battelle Columbus Labs.
E. A. Lloyd
Office of Fossil Energy, USDOE
D. C. McCoy
Conoco Coal Development Co., Huntington, W. Va.
G. A. McGinnis
Argonne National Lab.
J. E. Macko
Westinghouse Electric Corp., Madison, Pa.
T. O. Maginnis
The Foxboro Co., Foxboro, Mass.

- W. M. Managan
  - Argonne National Lab.
- H. C. March
  - Procon Inc., Des Plaines, Ill.
- R. P. Martin
  - Brown & Root, Inc., Oak Brook, Ill.
- G. G. Mayer
  - Grand Forks Energy Technology Center, USDOE
- N. J. Mazzocco
  - Pittsburgh Energy Technology Center, USDOE
- J. Meek
  - Inst. of Gas Technology, Chicago
- E. K. Merewether
  - BDM Corp., Albuquerque
- C. L. Miller
  - Office of Fossil Energy, USDOE
- M. L. Miller
  - Montana Energy and MHD R&D Inst., Butte
- W. R. Miller
  - Stearns-Roger, Inc., Homer City, Pa.
- W. C. Mines
  - ITT Barton, City of Industry, Calif.
- D. Moore
  - Laramie Energy Technology Center, USDOE
- T. P. Mulcahey
  - Argonne National Lab.
- E. J. Mullarkey
  - Aerojet Energy Conversion Co., Washington, D. C.
- J. D. Naylor
  - P&M Coal Mining Co., Du Pont, Wash.
- D. M. Nelson
  - Fluidyne Engineering Corp., Minneapolis
- G. R. Nelson
  - Honeywell, Inc., Minneapolis
- K. E. Nelson
  - Dow Chemical U.S.A., Plaquemine, La.
- M. S. Nutkis
  - Exxon Research & Engineering, Linden, N. J.
- N. M. O'Fallon
  - Argonne National Lab.
- V. J. Orphan
  - SAI, San Diego
- J. H. Oxley
  - Battelle Columbus Labs.
- P. Palmese
  - Universal Oil Products, Inc., Des Plaines, Ill.
- D. L. Phillips
  - Kaman Sciences Corp., Colorado Springs
- R. J. Platt
  - Exxon Research & Engineering Co., Florham Park, N. J.
- W. F. Podolski
  - Argonne National Lab.
- D. H. Pontius
  - Southern Research Inst., Birmingham

K. G. Porges
Argonne National Lab.
R. C. Post
Materials Technology Corp., Dallas
J. L. Powell, Jr.
Office of Fossil Energy, USDOE
A. G. Prentice
British Gas Corp., London, England
R. E. Pressey
Denver Research Inst., U. Denver
G. H. Quentin
Electric Power Research Inst., San Jose
D. E. Rapley
Stearns-Roger Engineering Corp., Denver
A. C. Raptis
Argonne National Lab.
R. Reeves
Hazen Research, Golden, Colo.
A. Rehmat
Inst. of Gas Technology, Chicago
H. Resnick
Chevron Research Co., Richmond, Calif.
H. L. Retcofsky
Pittsburgh Energy Technology Center, USDOE
T. Rhodes
Conoco, Inc., Ponca City, Okla.
G. F. Riedmuller
Leslie Co., Littleton, Colo.
D. L. Rittenhouse
EG&G, Idaho Falls
P. D. Roach
Argonne National Lab.
G. S. Rosenberg
Argonne National Lab.
F. A. Ruiz
Dow Chemical U.S.A., Plaquemine, La.
D. G. Sample
Sandia Labs., Albuquerque
R. A. Sapko
Brown & Root, Inc., Oak Brook, Ill.
R. O. Scandrol
Conoco Coal Development Co., Library, Pa.
W. M. Schirra, Jr.
Englewood, Colo.
P. Schroeder
Denver, Colo.
D. D. Schuresko
Oak Ridge National Lab.
M. A. Scott
U. Tennessee Space Inst., Tullahoma
P. C. Scott
Office of Fossil Energy, USDOE
M. G. Scroger
National Bureau of Standards, Washington

R. D. Shah
  Rockwell International, Canoga Park
G. C. Sine
  TRW Energy Systems Group, Morgantown, W. Va.
M. F. Singleton
  Lawrence Livermore Lab.
W. L. Slater
  Texaco, Inc., Montebello, Calif.
A. H. Smallbone
  A.H.S. Consultants, Engineers, La Crescenta, Calif.
J. Smith
  Laramie Energy Technology Center, USDOE
W. Smith
  Southern Research Inst., Birmingham
T. H. Sonnichsen
  Exxon Research & Engineering Co., Florham Park, N. J.
E. W. Spannhake
  White Consolidated Industries, Inc., Cleveland
R. A. Springer
  Materials Technology Corp., Dallas
R. R. Stalnaker
  C. F. Braun & Co., Alhambra
R. W. Stansfield
  Stearns-Roger, Inc., Homer City, Pa.
G. A. Stuart
  Dow Chemical Co., Midland, Mich.
W. S. Su
  Solar Energy Research Inst.
J. A. Sullivan
  Los Alamos Scientific Lab.
P. R. Tabor
  Hydrocarbon Research, Inc., Lawrenceville, N. J.
O. J. Tassicker
  Electric Power Research Inst., Palo Alto
D. R. Telesca
  Enviro Control, Inc., Rockville, Md.
M. W. Thornton
  Westinghouse Hanford Co.
D. A. Tichenor
  Sandia Labs., Livermore
V. S. Underhoffler
  Gilbert Associates, Inc., Reading, Pa.
A. P. Vander Klay
  Amoco Oil Company, Naperville, Ill.
A. F. Veneruso
  Sandia Labs., Albuquerque
D. J. Vermeer
  Ocean Minerals, Inc., Mountain View, Calif.
R. Waguespack
  Kamyr Valves, Glens Falls, N. Y.
H. A. Waller
  Consolidated Controls Corp., El Segundo
J. V. Walsh
  Jet Propulsion Lab.

J. C. F. Wang
  Sandia Labs., Livermore
L. W. Ward
  Curtiss-Wright Corp., Washington
G. G. Weth
  Office of Fossil Energy, USDOE
J. S. White
  Oak Ridge National Lab.
S. V. Williams, Jr.
  TOSCO Corp., Golden
H. U. Wiltsee
  Stearns-Roger, Inc., Denver
S. J. Wohadlo
  Inst. Gas Technology, Chicago
P. S. Wong
  Fairchild Stratos Div., Manhattan Beach, Calif.
R. J. Wright
  Office of Fossil Energy, USDOE
P. M. Yavorsky
  Pittsburgh Energy Technology Center, USDOE
J. Yerushalmi
  Electric Power Research Inst., Palo Alto
H. K. Zang
  Texaco, Inc., Beacon, N. Y.
A. H. Zoll
  Curtiss-Wright Corp., Wood-Ridge, N. J.
F. M. Zweibaum
  Barnes Engineering Co., Stamford, Conn.

Distribution for ANL-79-62

Internal:

W. E. Massey
N. M. O'Fallon (97)
L. Burris
E. J. Croke
B. R. T. Frost
C. E. Till
W. J. Sturm
R. S. Zeno
E. F. Bennett
W. L. Buck
T. R. Bump
H. Chang
C. E. Cohn
S. A. Cox
L. R. Dates
J. Depadro
R. W. Doering
J. J. Eichholz
W. A. Ellingson
E. F. Groh
C. L. Herzenberg
L. Habegger
C-C. Hsu
T. R. Johnson
A. A. Jonke
H. B. Karplus
L. W. Kirsch
A. E. Knox
L. G. LeSage
W. C. Lipinski
A. A. Longnecker
E. P. Lynch
M. J. McDaniel
G. A. McGinnis
W. W. Managan
J. F. Mech
T. P. Mulcahey
E. G. Pewitt
W. F. Podolski
K. G. Porges
A. C. Raptis
P. D. Roach
G. S. Rosenberg
S. J. Rudnick
M. H. Shackelford
S-H. Sheen
F. G. Teats
J. A. Wiesemes
A. B. Krisciunas
ANL Contract File
ANL Libraries (5)
TIS Files (6)

External:

DOE-TIC, for distribution per UC-89 (185)
Manager, Chicago Operations and Regional Office, DOE
Chief, Office of Patent Counsel, DOE-CORO
President, Argonne Universities Association
Applied Physics Division Review Committee:
  P. W. Dickson, Jr., Westinghouse Electric Corp.
  R. L. Hellens, Combustion Engineering, Inc.
  K. D. Lathrop, Los Alamos Scientific Lab.
  W. B. Loewenstein, Electric Power Research Inst.
  R. F. Redmond, Ohio State U.
  R. Sher, Stanford U.
  D. B. Wehmeyer, Detroit Edison Co.
T. Atwood, Office of Fossil Energy, USDOE
W. D. Bachalo, Spectron Development Labs., Costa Mesa, Calif.
R. J. Ballenger, Rockwell International, Canoga Park
P. M. Barker, Rockwell International, Canoga Park
M. J. Barrody, Catalytic, Inc., Wilsonville, Ala.
W. E. Baucum, Jr., U. Tennessee Space Institute, Tullahoma
P. Baumeister, Aerojet, Azusa
F. H. Bekker, Koppers Company, Inc., Pittsburgh
C. E. Berthold, Hazen Research, Inc., Golden, Colo. (2)
N. T. Bolt, British Gas Corp., London, England
D. L. Bonk, Babcock & Wilcox Co., Alliance, Ohio
R. T. Boos, Bethlehem Steel Corp., Bethlehem
H. Bozorgmanesh, Science Applications, Inc., Sunnyvale
N. C. Bradley, Union Carbide Corp., Oak Ridge
B. Brownstein, Battelle Columbus Labs.
L. E. Burkhart, Ames Lab.
G. W. Burns, National Bureau of Standards, Washington
C. W. Busch, Spectron Development Labs., Costa Mesa, Calif.
A. E. Cannon, Westran Corp., Santa Ana

C. T. Carroll, Foster Wheeler Energy Corp., Livingston, N. J.
T. X. Carroll, E. I. duPont de Nemours and Co., Wilmington
G. M. Caton, Oak Ridge National Lab.
R. J. Cerar, Pittsburgh Energy Technology Center, USDOE
G. J. Chelen, Westinghouse Electric Corp., Madison, Pa.
H. A. Clayton, Phillips Petroleum Co., Bartlesville
C. O. Cogburn, U. Arkansas
M. Cotter, Agoura, Calif.
R. D. Crabtree, General Atomic Co.
H. M. Crawford, Exxon Research & Engineering Co., Florham Park, N. J.
C. T. Crowe, Washington State U.
E. Cueller, Lawrence Berkeley Lab.
R. L. Currie, Babcock & Wilcox Co., Lynchburn
H. Deich, MDH Industries, Inc., Monrovia, Calif.
F. E. Diebold, Montana College of Mineral Science and Technology, Butte
W. M. Dillow, Gulf Science & Technology Co., Houston
G. I. Doering, Measurex Corp., Cupertino, Calif.
R. E. Dragoo, Stearns-Roger Engineering Corp., Denver
B. L. Draper, Sandia Labs., Albuquerque
R. L. Druva, Stearns-Roger, Inc., Denver
R. M. Dryden, Gulf Mineral Resources Co., Denver
A. K. Dubberly, Cameron Engineers, Denver
R. H. Duckstein, Gulf Research & Development Co., Pittsburgh
M. D. Durham, Denver Research Inst., U. Denver
D. Earnshaw, Laramie Energy Technology Center, USDOE
P. Echtler, Conoco Coal Development Co., Library, Pa.
F. T. Finch, Los Alamos Scientific Lab.
L. E. Fleming, Exxon Co., Baton Rouge
F. L. Fletcher, Rockwell International, Canoga Park
F. Fonzi, Fonzi and Associates, Cedar Hill, Tex.
R. Forney, Colorado School of Mines, Golden
R. W. Forsythe, Illinois Coal Gasification Group, Chicago
F. D. Freeburn, Morgantown Energy Technology Center, USDOE
W. Fuchs, Pittsburgh Energy Technology Center, USDOE
J. L. Gendler, Hydrocarbon Research, Inc., Lawrenceville, N. J.
R. J. Gendreau, Stone & Webster Engineering Co., Boston
V. A. Giroux, Phillips Petroleum Co., Bartlesville
T. Gozani, Science Applications, Inc., Palo Alto
D. R. Hajicek, Grand Forks Energy Technology Center, USDOE
R. M. Hamberg, TRW, Redondo Beach (2)
R. A. Hammond, Boeing Computer Services, Bellevue, Wash.
C. Harper, Consolidated Controls Corp., El Segundo
W. P. Harrington, Stearns-Roger Engineering Corp., Denver
W. H. Hartwig, U. Texas at Austin
G. R. Hill, U. Utah
B. R. Hoover, ARMCO, Inc., Middletown, Ohio
C. G. Houser, Phillips Petroleum Co., Homer City, Pa.
M. J. Howe, Leeds & Northrup, North Wales, Pa.
J. S. Hubacher, TRW Energy Systems Group, McLean, Va.
D. E. Hull, Phillips Petroleum Co., Homer City, Pa.
H. N. Hulsman, Koninklijke/Shell-Laboratorium, Amsterdam, The Netherlands
D. E. Hyatt, Hazen Research, Inc., Golden
J. Z. Inskeep, Jet Propulsion Lab.
D. H. Jaeger, WOP/SDC, Los Angeles
J. E. Janssen, Honeywell, Inc., Minneapolis
L. A. Jeffers, Babcock & Wilcox Co., Alliance, Ohio
D. T. Johnson, TOSCO Corp., Golden

D. G. Jones, Radian Corp., Pasadena
H. T. Jones, Office of Fossil Energy, USDOE
H. Kaplan, Barnes Engineering Co., Stamford, Conn.
N. L. Kautsky, Stearns-Roger, Inc., Denver
K. Kawatra, Michigan Technological U.
D. M. Kelly, Stearns-Roger, Inc., Homer City, Pa.
F. G. King, Howard U.
D. I. Knudsen, EMA, Inc., St. Paul, Minn.
P. H. Lafave, Combustion Engineering, Inc., Windsor
R. V. Laney, Duxbury, Mass.
R. C. LaSell, Rosemount, Minneapolis
T. K. Lau, Office of Fossil Energy, USDOE
E. W. Lazor, Babcock & Wilcox Co., Alliance, Ohio
B. S. Lee, Inst. of Gas Technology, Chicago
J. W. Lee, The Bendix Corp., Lewisburg, W. Va.
W. H. Levers, Standard Oil Co. of California, San Francisco
D. W. Lewis, U. Virginia
R. D. Litt, Battelle Columbus Labs.
E. A. Lloyd, Office of Fossil Energy, USDOE
D. C. McCoy, Conoco Coal Development Co., Huntington, W. Va.
J. E. Macko, Westinghouse Electric Corp., Madison, Pa.
T. O. Maginnis, The Foxboro Co., Foxboro, Mass.
H. C. March, Procon Inc., Des Plaines, Ill.
R. P. Martin, Brown & Root, Inc., Oak Brook, Ill.
G. G. Mayer, Grand Forks Energy Technology Center, USDOE
N. J. Mazzocco, Pittsburgh Energy Technology Center, USDOE
J. Meek, Inst. of Gas Technology, Chicago
E. K. Merewether, BDM Corp., Albuquerque
C. L. Miller, Office of Fossil Energy, USDOE
M. L. Miller, Montana Energy and MHD R&D Inst., Butte
W. R. Miller, Stearns-Roger, Inc., Homer City, Pa.
W. C. Mines, ITT Barton, City of Industry, Calif.
D. Moore, Laramie Energy Technology Center, USDOE
E. J. Mullarkey, Aerojet Energy Conversion Co., Washington, D. C.
J. D. Naylor, P&M Coal Mining Co., Du Pont, Wash.
D. M. Nelson, Fluidyne Engineering Corp., Minneapolis
G. R. Nelson, Honeywell, Inc., Minneapolis
K. E. Nelson, Dow Chemical U.S.A., Plaquemine, La.
M. S. Nutkis, Exxon Research and Engineering, Linden, N. J.
V. J. Orphan, SAI, San Diego
J. H. Oxley, Battelle Columbus Labs.
P. Palmese, Universal Oil Products, Inc., Des Plaines, Ill.
R. G. Patterson, Air Pollution Technology, Inc., San Diego
S. P. Perkins, Wormser Engineering, Inc., Middleton, Mass.
D. L. Phillips, Kaman Sciences Corp., Colorado Springs
R. J. Platt, Exxon Research & Engineering Co., Florham Park, N. J.
D. H. Pontius, Southern Research Inst., Birmingham
R. C. Post, Materials Technology Corp., Dallas
J. L. Powell, Jr., Office of Fossil Energy, USDOE
A. G. Prentice, British Gas Corp., London, England
R. E. Pressey, Denver Research Inst., U. Denver
G. H. Quentin, Electric Power Research Inst., San Jose
D. E. Rapley, Stearns-Roger Engineering Corp., Denver (2)
R. Reeves, Hazen Research, Golden, Colo.
A. Rehmat, Inst. Gas Technology, Chicago
H. Resnick, Chevron Research Co., Richmond, Calif.
H. L. Retcofsky, Pittsburgh Energy Technology Center, USDOE

T. Rhodes, Conoco, Inc., Ponca City, Okla.
G. F. Riedmuller, Leslie Co., Littleton, Colo.
M. J. Rini, Aerojet Energy Conversion Co., Sacramento
D. L. Rittenhouse, EG&G, Idaho Falls
F. A. Ruiz, Dow Chemical U.S.A., Plaquemine, La.
D. G. Sample, Sandia Labs., Albuquerque
R. A. Sapko, Brown and Root, Inc., Oak Brook, Ill.
R. O. Scandrol, Conoco Coal Development Co., Library, Pa.
W. M. Schirra, Jr., Englewood, Colo.
P. Schroeder, Denver, Colo.
D. D. Schuresko, Oak Ridge National Lab.
M. A. Scott, U. Tennessee Space Inst., Tullahoma
P. C. Scott, Office of Fossil Energy, USDOE
M. G. Scroger, National Bureau of Standards, Washington
R. D. Shah, Rockwell International, Canoga Park
G. C. Sine, TRW Energy Systems Group, Morgantown, W. Va.
M. F. Singleton, Lawrence Livermore Lab. (2)
W. L. Slater, Texaco, Inc., Montebello, Calif.
A. H. Smallbone, A.H.S. Consultants, Engineers, La Crescenta, Calif.
J. Smith, Laramie Energy Technology Center, USDOE
W. Smith, Southern Research Inst., Birmingham
T. H. Sonnichsen, Exxon Research & Engineering Co., Florham Park, N. J.
E. W. Spannhake, White Consolidated Industries, Inc., Cleveland
R. A. Springer, Materials Technology Corp., Dallas
R. R. Stalnaker, C. F. Braun & Co., Alhambra
R. W. Stansfield, Stearns-Roger, Inc., Homer City, Pa.
G. A. Stuart, Dow Chemical Co., Midland, Mich.
W. S. Su, Solar Energy Research Inst.
J. A. Sullivan, Los Alamos Scientific Lab.
P. R. Tabor, Hydrocarbon Research, Inc., Lawrenceville, N. J.
O. J. Tassicker, Electric Power Research Inst., Palo Alto
D. R. Telesca, Enviro Control, Inc., Rockville, Md.
Tempere U. of Technology, Tempere, Finland
M. W. Thornton, Westinghouse Hanford Co.
D. A. Tichenor, Sandia Labs., Livermore
V. S. Underhoffler, Gilbert Associates, Inc., Reading, Pa.
N. Vagelatos, IRT Corp., San Diego
A. P. Vander Klay, Amoco Oil Company, Naperville, Ill. (2)
A. F. Veneruso, Sandia Labs., Albuquerque
D. J. Vermeer, Ocean Minerals, Inc., Mountain View, Calif.
D. V. Vukovic, Belgrade U., Belgrade, Yugoslavia
R. Waguespack, Kamyr Valves, Glens Falls, N. Y.
H. A. Waller, Consolidated Controls Corp., El Segundo
J. V. Walsh, Jet Propulsion Lab.
J. C. F. Wang, Sandia Labs., Livermore
L. W. Ward, Curtiss-Wright Corp., Washington
G. G. Weth, Office of Fossil Energy, USDOE
J. S. White, Oak Ridge National Lab.
S. V. Williams, Jr., TOSCO Corp., Golden (2)
H. U. Wiltsee, Stearns-Roger, Inc., Denver
S. J. Wohadlo, Inst. Gas Technology, Chicago
P. S. Wong, Fairchild Stratos Div., Manhattan Beach, Calif.
P. M. Yavorsky, Pittsburgh Energy Technology Center, USDOE
J. Yerushalmi, Electric Power Research Inst., Palo Alto
H. K. Zang, Texaco, Inc., Beacon, N. Y.
A. H. Zoll, Curtiss-Wright Corp., Wood-Ridge, N. J.
F. M. Zweibaum, Barnes Engineering Co., Stamford, Conn.

☆ U. S. GOVERNMENT PRINTING OFFICE: 1980-653-204