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THE PROCEEDINGS OF THE 1977 SYMPOSIUM ON INSTRUMENTATION AND PROCESS CONTROL FOR FOSSIL DEMONSTRATION PLANTS

July 13-15, 1977

Hyatt Regency O'Hare

Chicago, Illinois

ERDA-AUA-USDOE

CHICAGO SECTION

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Instrument Society of America - Chicago Section

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The funding of the symposium by the ERDA Division of Major Facilities Project Management and the valuable guidance of J. L. Powell, Jr., Components Branch Chief, are gratefully acknowledged.

The many organizations, including national laboratories, universities, government, and private industry, are thanked for the efforts of their employees involved in any way with the symposium. The considerable time and energy so invested led to an extremely successful symposium and an excellent beginning for solution of the instrumentation and control problems of fossil demonstration plants.

In view of this symposium's success, the Symposium Committee is confident the 1978 Symposium in Newport Beach, California, June 19-21, 1978 will be at least as successful.

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Applied Physics Division
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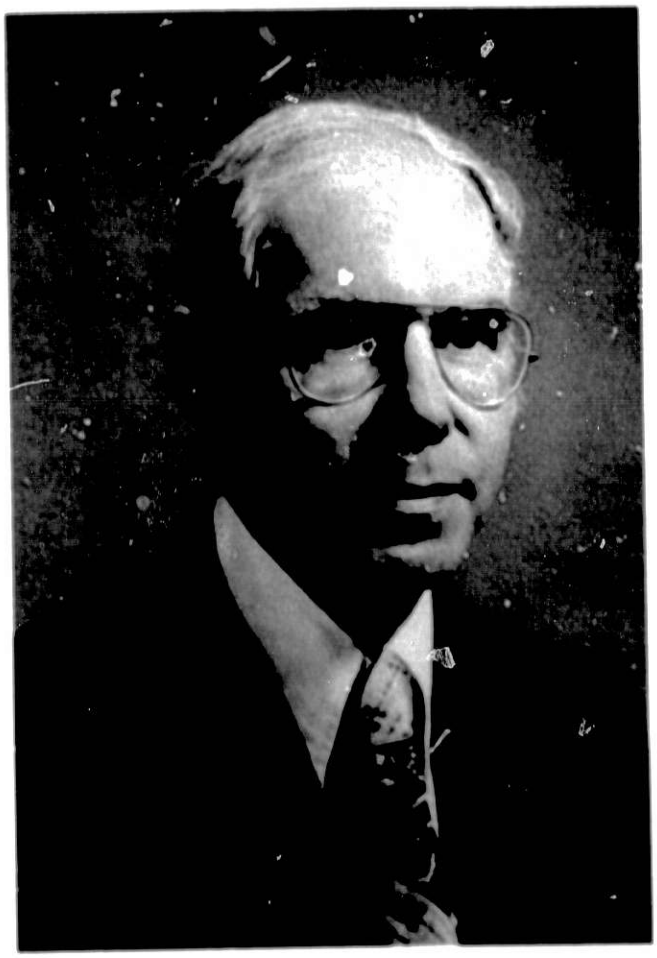
OPENING REMARKS



R. G. Sachs, Laboratory Director
Argonne National Laboratory
Argonne, Illinois

OPENING REMARKS

Dr. Robert G. Sachs

Laboratory Director

Argonne National Laboratory

I think my responsibility is to welcome you here in the name of Argonne National Laboratory, one of the sponsors of this meeting, and it is a pleasure for me to have that opportunity.

I do think a word of explanation may be appropriate because, ever since we have become identified at Argonne with an interest in fossil energy, many people who have been in the fossil energy business for a much longer time than we have appropriately raised the question, "What in the world is Argonne doing in our business?" I think that has a great bearing on our role in this particular meeting. How did we get into the fossil energy business? The reason this question is asked is that Argonne is usually associated with nuclear energy and related basic research. Now, of course, these fields of work involve very broad areas of science, technology, and engineering, and they involve in particular state-of-the-art technology. In state-of-the-art technology, it is most important to have available reliable and precise measurements of all of the parameters that are involved. The measurements must often be made under the most extreme adverse conditions. The development of improved processes for converting fossil fuels into useful work, which is what the fossil energy business is all about, requires measurements under conditions that are similar to those with which one is involved in the nuclear energy business — measurements at high temperature, high pressure, in very corrosive environments, and so on. Therefore we have at least this one thing to offer to the development of fossil energy, a great deal of experience in the development of very sophisticated instrumentation for measurements under very extreme conditions, and we are much involved in applying these techniques developed over the years to the instrumentation problems which are the subject of this meeting.

You are here, as I understand it, to address such questions and come to a consensus as to what the real problems are. I'm sure you're going to find that there are plenty of real, very challenging problems and you'll leave this conference with more than enough to do. I'd like to wish you good luck in that endeavor. Thank you.

OVERVIEW OF COAL CONVERSION PROCESS

B. S. Lee, Vice President Process Research
Institute of Gas Technology
Chicago, Illinois

OVERVIEW OF COAL CONVERSION PROCESSES

by
B. S. Lee
Institute of Gas Technology

1. INTRODUCTION

The need to utilize coal, our most abundant domestic fossil energy resource, has been long recognized. The need to accelerate and expand the utilization of coal has only been broadly accepted in the last few years, as domestic supply of oil and gas continues to diminish. Spurred on by the rapidly rising price of imported oil and the increasing reliance upon foreign oil supply, questions of national security and the balance of payment made us realize the critical need to develop domestic energy resources. Stimuli such as deregulating natural gas and providing investment credit for exploring for new oil and gas would help to increase the energy supply. Nonetheless, the most readily available energy source in the U. S. is coal.

This fact is well recognized by both the Administration and Congress. The need to expand coal utilization was clearly enunciated in the President's energy message. The question is no longer whether we should use more coal, but how best to use it. Our mission, as technology developers, is to bring forth technologies to allow the most efficient, environmentally acceptable, utilization of the energy in coal, from the coal mine to end use. While energy conservation is undeniably important, it is just as important to increase the energy supply. These two actions form the two corner stones of a viable energy policy.

Coal is a complex material whose composition varies with the seam and the location. Its basic chemical structure has never been fully established, so that coal characterization is largely done by empirical means. Coal has been characterized by its basic atomic elements, and by maceral constituents. It contains solid mineral matters in the form of ash, which has a highly variable composition. Some of the components in ash occur in trace quantities, but are important for emission and environmental control.

We can group all uses of coal under the heading of "Coal Conversion Processes," if we define conversion as changing coal from its complex "as mined" form into a clean energy form. This kind of conversion covers both direct conversion, such as combustion in which the coal is converted into a form of thermal energy such as high-pressure steam, and indirect conversion, where coal is converted to a synthetic pipeline gas, low-Btu fuel gas, or clean liquid fuel. With this definition, let me brief you on the general picture and give you an overall review of the technologies being developed in direct and indirect coal conversion processes.

For you who are interested in instrumentation and controls, two types of measurements are taken in coal conversion processes:

1. Compositional analyses
2. Process parameters such as temperature, pressure, flow, density, and levels.

The difficult part about making compositional analyses is that a representative sample must first be taken. This is difficult because many solid samples are not in themselves homogeneous. Other samples involve gases and solids, and a sampling method must be devised so that the sample represents a true concentration of solids in the gas stream.

Conditioning the sample is difficult because samples contain not only dust, but possibly condensable liquids, including water, hydrocarbon oils, or heavy viscous tars. Because many of these processes occur at high temperatures and pressures, the sampling device must be able to take samples continuously, safely and reliably, while not being obstructed by condensation or fines collection that could cause plugging.

Once a sample is taken and properly conditioned, the compositional analysis can often be done with standard equipment, such as individual component analyzers, mass spectrometers, or gas chromatographs.

In measuring process parameters, it is a challenge to overcome physical restrictions imposed by high pressure, high temperature, and possibly corrosive atmospheres accentuated by the high temperature and

pressure. Locating sensing elements to obtain a representative measurement of the process conditions, while protecting them from an adverse environment, demands careful design of thermowells, pressure probes, and level detectors.

2. DIRECT COAL CONVERSION

Besides conventional coal combustion processes involving either stack gas scrubbing or adding limestone to the combustor, the new advance in direct combustion is fluid-bed combustion. The important factor that motivated developing this technique is that intimate mixing and high-heat transfer rates mean coal can be completely combusted at the relatively low temperature of 1600°F, while conventional slagging cyclone combustors operate at 2500° to 3000°F. Because of the low temperatures in fluid-bed combustion, far less nitrogen oxides are formed in the flue gas. Limestone in the fluidized bed permits removing sulfur compounds so that the flue gas can be discharged directly into the atmosphere. The excellent heat transfer characteristics of a fluidized bed are utilized in a compact heat transfer section; this allows high-pressure steam to be generated in tubes immersed in the fluidized bed.

Several fluid-bed combustion units have been tested in England, including one pressurized at 6 atmospheres, at NRDC/BCURA. In the U.S., development work by Pope, Evans, and Robbins has led to designing and operating test units producing 5000 lbs/hr of steam. Based on these results, a large demonstration plant was built at Rivesville, West Virginia. There, the unit is integrated into a power plant and includes a fluidized-bed combustor producing 300,000 lb/hr of steam. This is equivalent to 30 megawatts of power from 15 tons/hr of coal.

Fluid-bed combustion can replace the conventional steam boiler in a power plant. Because the high-pressure steam is used principally for power generation, the overall coal utilization is still limited by the conversion efficiencies of conventional electric power generation. The nation's energy demand requires power generation, and fluid-bed combustion has a potential to provide improved steam generation for this power generation. If co-generation is eventually desired, then either fluid-bed combustion or conventional steam raising could be adapted for co-generation of power and heating steam.

The scale-up of fluid-bed combustors has been considered in a recent report by Babcock and Wilcox for the Electric Power Research Institute. They were primarily concerned with the life of metal parts, such as steam coils, internal cyclones, and hot precipitators, which are exposed to the corrosive, erosive conditions in a fluid-bed. Because the steam coils contain high-pressure steam, their strength is vitally important for satisfactory operation and for safety.

3. INDIRECT CONVERSION

Gasification

One possibility in converting coal to gas is to produce high-Btu, or synthetic pipeline gas. This is interchangeable with natural gas and can be transmitted and distributed in existing natural gas pipeline systems. The other route is to produce low-Btu fuel gas, which is either distributed over a relatively short radius to concentrated industrial users, or is used for electrical power generation in a combined cycle.

A. High-Btu Gasification

Short of burning coal directly to provide heat, the most efficient way to use coal as a clean burning fuel to heat homes and businesses is to convert the coal to high-Btu gas. The total system (from coal conversion, through transmission and distribution, to end use) costs less than one-third as much as using coal to generate electricity to provide heat.

High-Btu gasification processes can be classified by their mode of gasifier operation, which largely determines the process efficiency and cost. Instrumentation and control development centers around the gasifier. This unit not only controls the efficiency and operability of the entire process, but contains the most severe environment for making measurements.

1. Moving-Bed Gasifiers. Here, gasification occurs in a bed of coal moving downward, countercurrent to upward flowing gas, similar to a blast furnace. The Lurgi process, which can be applied to non-caking U. S. western coal, is commercially available. Several commercial plants have been proposed in the U. S. and are awaiting approval by the Federal Power Commission and other favorable Government actions, such as loan guarantees.

The gasifier operates at around 350 psig pressure under non-slagging conditions. Temperatures reach about 2200°F, depending upon the steam and oxygen content of the gas. These gasifiers are typically 10 feet in diameter, and receive dry feed through cyclic lockhoppers. A typical gasifier atmosphere tends to be reducing; depending on the location in the gasifier, it varies in the proportion of CO, H_2, CO_2, steam, methane, and the lesser amounts of ethane, propane, and other hydrocarbons or vaporized tars. Sulfur compounds abound, consisting mostly of hydrogen sulfide, plus lesser amounts of COS, and other organic sulfur compounds. Some of the chlorine in the coal might be volatilized. Most of the nitrogen is converted to ammonia plus small amounts of HCN. Most of the oxygenated hydrocarbons in the coal become carbon oxides or steam, with a portion converted to phenol.

On the development scale, a slagging version of the Lurgi gasifier is being developed at the Westfield, Scotland facility for caking bituminous coal. The slagging mode increases the throughput of the gasifier and simultaneously requires less steam flow than the non-slagging mode. A rotating rabble arm breaks up any agglomerates formed from the caking coal. Refractory life in the slagging area is an operational concern. The slagging Lurgi process is the subject of a contract between ERDA and a group of companies headed by Conoco for the design of a demonstration-size plant.

Other developments of the Lurgi process include constructing increasingly larger diameter vessels and operating at higher pressures, in the 1000 psig range. These factors increase throughput to reduce the number of parallel gasifiers in the commercial plant and to make the process more efficient by producing larger percentages of methane directly in the gasifier.

2. Fluidized-Bed Gasifiers. The Winkler process is available commercially. However, it operates at essentially atmospheric pressure and therefore only produces CO plus H_2, with negligible quantities of methane. This makes a high-Btu gas process based on Winkler inefficient and costly, and no such commercial plant is planned in the U. S. We understand that development work is underway in Europe for higher-pressure operations of the Winkler process.

Several pressurized fluidized-bed operations are in the development stage. The HYGAS process using steam-oxygen gasification is undergoing integrated pilot plant testing in Chicago. Technical feasibility of operating with all three major U. S. coal types (lignite, subbituminous, and bituminous) has been demonstrated. This process operates at around 1000 psig in the gasifier, under non-slagging, dense-phase, fluidized-bed conditions. Coal feed to the gasifier is via a slurry. Maximum temperature in the steam-oxygen gasifier bed is expected to be less than 1850°F. Several stages of fluidized-bed operation are contained in one pressure vessel, with internal solids transfer. The combination of high-pressure and non-slagging gasification results in about two-thirds of the total methane being produced directly in the gasifier. Therefore, among the first and second generation high-Btu processes, HYGAS has the highest overall thermal efficiency (over 70%). The HYGAS process will be scaled up to demonstration-plant size in a conceptual design effort by Procon, Inc. A commercial size HYGAS reactor will be about 20 feet in diameter.

The CO_2 Acceptor process developed by Conoco Coal Development Company at Rapid City, South Dakota is designed for lignite and subbituminous coals. It operates at 150 psig, while the gasifier temperature is maintained at around 1600°F and the acceptor generator around 1900°F. Solids are fed to the reactor via lockhoppers and are circulated between the gasifier and regenerator vessel. Successful operation has been demonstrated with lignite coal.

The Synthane process, being developed by the ERDA Pittsburgh Energy Research Center at Bruceton, Pennsylvania, uses a single stage fluidized-bed gasifier operating at 1000 psig. About two-thirds of the carbon is gasified; the remainder being discharged from the system as byproduct char. Coal is fed to the gasifier via lockhoppers. Temperatures in the gasifier reach about 1700°F. Initial operation with subbituminous coal is in progress, with reasonable success at 600 psig operation reported.

3. Entrained Bed Gasifiers. The only commercially available entrained-gasifier process is the Koppers-Totzek process. Because this system operates at near atmospheric pressure, negligible amounts of methane are formed in the gasifier. Therefore, the process is costly and inefficient for pipeline gas production. No Koppers-Totzek high-Btu gas plants are planned in the U. S.

   The advantage of the Koppers-Totzek process is that it can accept any type of coal feed of any size, because the coal must be pulverized before being fed to the gasifier. The operation is in a slagging mode, with temperatures of 2500° to 3000°F. The high temperature, accompanying slagging, results in low process efficiency and high oxygen consumption per unit coal fed.

   Koppers is developing a 150 to 200 psig version of their reactor to increase direct methane yield and to increase the throughput of coal per gasifier.

   The COGAS process is classified as an entrained bed operation because the heat generation stage operates in an entrained mode with a slagging bottom, even though the circulating heat carrier is in a fluidized bed. This process combines a COED oil-making front-end with a back-end that generates a low-methane synthesis gas from the residual char of the COED front-end. The reactor pressure

is low, less than 100 psig, while the temperature in the slagging zone is 2500° to 3000°F. Coal feed to the reactor is by dry lockhopper. Although this process is the subject of a contract between ERDA and the Illinois Coal Gasification Group for a demonstration plant design, it has not yet been demonstrated on a fully integrated basis in the pilot plant.

Among the second generation processes being developed on the pilot plant scale, the BIGAS process of Bituminous Coal Research, Inc. at Homer City, Pennsylvania uses an entrained-bed reactor, operating in two stages at around 1000 psig pressure for improved efficiency. Temperatures in the slagging zone reach 2500° to 3000° F and feed to the reactor is via a water slurry. Initial operation is underway with subbituminous coal.

B. Low-Btu Gasification

The difference between low- and high-Btu operation is that forming methane is unimportant in producing fuel (low-Btu) gas. Because fuel gases are used locally or distributed within a relatively short radius, the low-Btu gas processes try to produce CO-H_2 mixtures rather than large quantities of methane. This makes high pressures unnecessary for methane formation. The only reason to operate in the 350 to 400 psig range is to produce a fuel gas for combined cycle power generation. For industrial use, pressures of 100 to 150 psig are sufficient.

With air as the gasifying medium, the product gas typically has a heating value of around 150 Btu/SCF. However, if high-purity oxygen is used, the heating value of the fuel gas is about 300 Btu/SCF. For combined cycle operation, air is typically used, as the mass flow through the gas turbine is the key design consideration. For low-Btu fuel gas, oxygen is used to generate a higher-heating-value gas that is more easily adapted to existing burners.

On the commercial scale, various processes for low-Btu gas generation also include moving bed reactors of the Lurgi type, slagging gasifiers of the Koppers-Totzek type, and fluidized-bed reactors of the Winkler type.

Among second-generation processes in the fluidized-bed category, the IGT U-Gas process is a single-stage gasifier operating at temperatures up to 1900°F in a non-slagging mode. This system is the subject of a demonstration plant project under negotiation between the city of Memphis and ERDA. In the entrained bed category, the Texaco slagging gasifier, (with peak temperatures of 3000°F), is under negotiation between W. R. Grace and ERDA as another candidate for a demonstration plant design.

Overall, from an instrumentation and control standpoint, the conditions encountered in low-Btu gas operation are no more severe than those encountered in high-Btu operation. The temperature levels are comparable, depending on the process types, but in general the pressures are lower in low-Btu gas production. If the instrumentation and control problems can be solved for high-Btu operations, then they certainly can be solved for the low-Btu gas systems.

C. Coal Liquefaction

One way to produce liquids from coal is to first make synthesis gas, using coal gasification, and then build up the liquid molecules by reacting CO-H_2 mixtures over Fischer-Tropsch catalysts. The Germans demonstrated such systems during World War II. The instrumentation and control requirements, however, fall basically within the ranges of the gasification systems. In the liquid synthesis step, the temperature is kept below 1000°F.

There are two ways to directly produce liquids from coal. One is to use pyrolysis, whereby the coal is heated to release a fraction of it as liquid products. The FMC COED process, which operates via a multi-stage fluidized-bed system, is one example. The pressure is less than 100 psig, with a peak temperature of 1600°F.

The other approach is by hydrogenation. The more hydrogen that is added to the coal during the solvation process, the lighter the cuts of syncrude produced. The Solvent Refined Coal (SRC) process, which involves adding just enough hydrogen for some desulfurization, is being developed by Gulf at the Fort Lewis, Washington pilot plant. The purpose is to produce a de-ashed and desulfurized coal for boiler fuel. The solvation takes place at pressures of around 1500 psig with a peak temperature of

850°F. On the other hand, adding more hydrogen to the process, using a catalyst, produces a lighter syncrude. This is the case with the H-Coal process being developed by HRI and Ashland Oil at Catlettsburg, Kentucky. Pressures in the range of 3000 psig and peak temperatures of 850°F are employed.

In coal liquefaction, it is difficult to compare the value of the syncrude with natural crude. Syncrude from coal typically contains a lot of nitrogen, making it undesirable for further refining by conventional technology. Unlike high-Btu or low-Btu gases, which can be used directly in industrial application, syncrude from coal requires careful consideration and modifications in refinery operations before it can be accepted as feedstock for further processing. For this reason, the syncrude should not be compared in value to natural crude, and its cost should not be calculated on a dollar per million Btu basis and compared with the cost of natural crude.

4. SUMMARY

From an instrumentation and control standpoint, I see no requirements for measuring temperatures, pressures, or flow quantities that exceed the bounds of present knowledge. The problem is applying these primary process parameter measurements to environments of reasonably high temperature and pressure, combined with a potentially corrosive gaseous atmosphere. Adapting suitable materials to serve as containers for the measuring elements would allow these measurements to be taken satisfactorily. The measurement of derived process parameters, such as bed levels, bed densities, or solids circulation rates, can be adapted from pressure differential measurements or other primary process parameters, although improvements are always desirable. From a severity standpoint, instrumentation developed for high-Btu gas operation, should be operable for all coal conversion processes.

Although advances in instrumentation and control technology are always desirable and anticipated, unlike nuclear energy development (with the demands posed by radioactivity), or the space program (with demands of extreme reliability under remote control) coal conversion does not

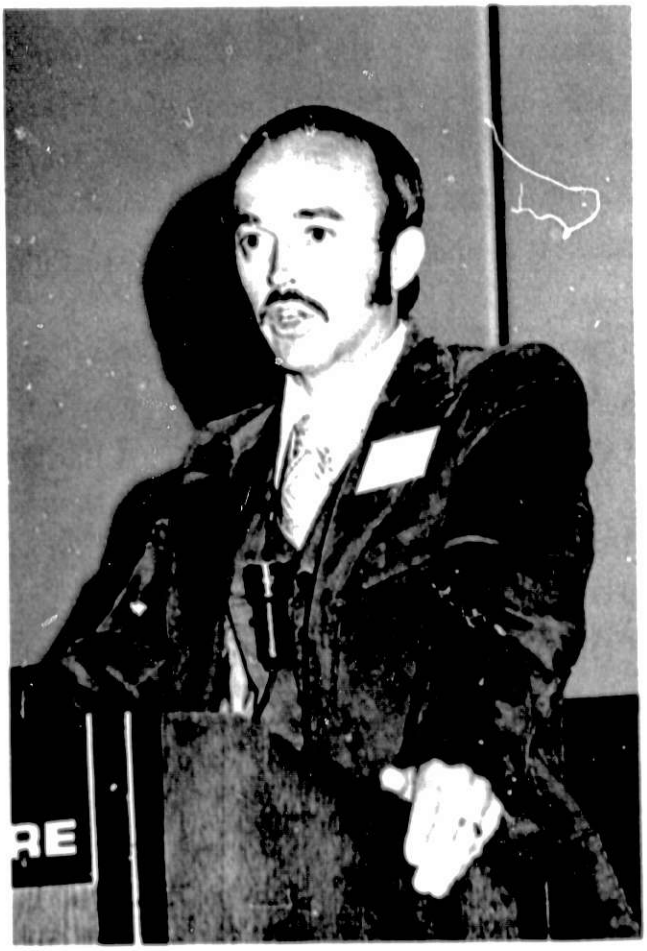
present any new dimensions for instrumentation and control. It is a "do-able" technology today. With these observations, I believe you are ready to get into the details of the instrumentation needs of each category of coal conversion processes.

PROBLEMS SESSION

Session Chairperson

T. K. Lau
ERDA-Fossil Energy
Division of Major Facilities Project Management
Washington, D. C.

INSTRUMENTATION DEVELOPMENT AND APPLICATION AT THE WESTINGHOUSE COAL GASIFICATION PDU



J. E. Macko
Westinghouse Research Development Center
Madison, Pennsylvania

INSTRUMENTATION DEVELOPMENT AND APPLICATION AT THE WESTINGHOUSE COAL GASIFICATION PDU

J.E. Macko, L.A. Salvador, P. Cherish, G. Haldipur
Westinghouse Research & Development Center

INTRODUCTION AND SUMMARY

Under the sponsorship of the Energy Research and Development Administration, Westinghouse Electric Corporation is developing a low Btu coal gasification process for use in combined cycle power generation. The process can utilize a variety of high sulfur, caking coals or non-caking coals to produce a clean, combustible gas which has a heating value on the order of 120 Btu/scf.

The gasification of the coal takes place in two fluidized bed reactors. In the first, the devolatilizer, coal fed from lock hoppers enters the reactor through a draft tube into a fluidized bed which operates at 230 psig and 1600°F. Devolatilized char recirculates around the draft tube and dilutes the incoming coal, thus preventing the formation of agglomerates as the coal passes through its plastic stage during heating. Dolomite is also circulated in the fluidized bed to remove the sulfur present as H_2S. Three product streams from the devolatilizer are char, sulfided dolomite, and low-Btu product gas.

The char from the devolatilizer is fed to the second reactor, the gasifier, where it is reacted with steam and air. The combustion reaction provides the heat for the entire process and also causes the ash present in the char to agglomerate at about 2000°F. These heavier, larger ash particles become defluidized and are drawn from the bed. The steam-carbon reaction is used to gasify the remainder of the carbon not combusted by air. It moderates the reaction temperature and provides the low-Btu gas which is introduced into the devolatilizer as the fluidizing medium.

Since August 1972, a three-phased effort has been in progress: bench scale and analytical work, pilot scale development on a 1200 lb/hr Process Development Unit (PDU), and scale-up studies for a commercial scale plant. The PDU has been used since January 1975 to conduct process development studies on the coal gasification portion of the system. First, the devolatilizer reactor was evaluated using a variety of coal feedstocks at a

number of process conditions. These tests were useful in demonstrating the feasibility of this portion of the process. Following the devolatilizer evaluations during 1975 and 1976, the gasifier reactor evaluation began in October 1976 to study char combustion, ash agglomeration, and char gasification.

The tests being performed with the PDU have three primary goals:

- To develop an efficient, operable process.
- To produce process design and operating data for use in scaling up to commercial plants.
- To develop and evaluate hardware and subsystem designs which may be used in scaled-up plants.

Part of the third goal is the evaluation of instrumentation and control systems to permit a selection of acceptable components for larger scale gasification plants. This evaluation consists, in the main, of utilizing off-the-shelf components and adapting them to the special application and hostile environments found in a typical coal conversion plant. This adaptation sometimes requires either a redesign of the basic instrument or the design of a suitable interface to the process.

In addition to the adaptation and evaluation of state-of-the-art instrumentation, it has often been necessary to develop special purpose instruments. This has been required in situations for which no instruments are commercially available to adequately perform the measurement or control task or in those for which existing instruments do not perform as planned because of the conditions actually encountered in the plant.

This paper presents the results of both evaluative and adaptive functions with respect to the data acquisition and process control instrumentation used in the 15 t/d PDU.

The problems encountered in the use of standard electronic and pneumatic sensors, transmitters, recorders, and controllers have generally been related to the interfacing of these components to the process and not in the operation of the units themselves which, in the case of the electronic instruments, have had excellent performance. High temperature thermocouples initially failed frequently but these problems were solved by a careful selection of sheath, well, and insulator materials to optimize their performance in both oxidizing and reducing atmospheres. In addition, an arrangement was designed to permit safe replacement of thermocouples in the reactors while

the process was at high pressure and temperature. Likewise, bed density and pressure drop measurements were essentially trouble free when a purged "rod-out" arrangement was satisfactorily implemented.

Solids flow measurement by three methods - starwheel feeders speed monitoring, belt weighers, and lock hopper load cells - has been satisfactory. Although the load cells did not give reproducible results initially, these units are now reliable solids flow measurement devices as a result of changes in the piping and supports on the lock hoppers themselves to eliminate false loads on the sensors. Fluidized bed level measurement using a nuclear densitometer has had excellent results and the levels indicated by this device compare favorably with levels measured by differential pressure devices. The densitometer is also used to measure ash-to-char interfaces in the gasifier.

On-line gas composition monitoring by gas chromatograph continues to present operating problems. These problems relate primarily to gas conditioning prior to analysis in the unit. The cleaning devices in the commercially available units are inadequate for the product gas produced in most plants without additional cleaning by filtration, cyclonic particulate removal, or scrubbing. In addition, the whole problem of obtaining a representative sample from a hot gas stream is under development by a number of investigators and remains unsolved in a practical sense. We are developing a system that can in-situ separate particulates, tars, water, and clean product gas for individual analyses.

Other instrument development efforts were completed or are on-going in addition to this product gas characterization. One involves the solution of a difficult flame detection and management problem associated with propane combustion at 200 psig. Ultraviolet detection devices were found to be inadequate and were replaced by infrared sensors and a parallel thermocouple system. Combustion zone temperature measurement in the gasifier has been unsuccessful with pyrometric devices but has had some success with thermocouples. Internal solids circulation rate measurements by a Doppler radar technique has met with some success which has encouraged further work in this area.

HIGH TEMPERATURE MEASUREMENT

The pilot plant utilizes two types of thermocouples - type K (chromel alumel) and W-5%/W-26% (tungsten 5% rhenium and tungsten 26% rhenium). No

major problems were encountered with the type K since these were used in lower temperature and less reactive areas. Problems were experienced with the high temperature W-5%/W-26% thermocouples. The plant was designed utilizing a Hastalloy-X thermowell with a type E industrial head. The thermocouple inside this well consisted of a moly-sheathed, disilicide coated, tungsten-rhenium thermocouple with a grounded junction and a non-compacted MgO insulator. These units were made in a variety of different lengths to match specific immersion depth and penetration depth requirements. This resulted in severe inventory problems for spare assemblies since they were non-standard dimensionally.

Problems arose with the "as built" configuration when devolatilization tests began early in 1975. During testing of the two synthesis gas generators, shown in Figure 1, temperatures at the exit of the burners exceeded 2200°F in both oxidizing and reducing atmospheres at a pressure of approximately 230 psi. Frequent flame failures were experienced due to inadequate flame management design, and the thermocouples and wells were subjected to many cycles of flame exposure and cold purge gas exposure. Failures resulted from:

- Thermowell degradation and well failure due to nitridation and oxidation.
- Open thermocouple junctions due to severe temperature cycling.

As the tests progressed into the devolatilization of various coals in conjunction with operation of the synthesis gas generators, thermocouple and well failures continued. The Hastalloy-X wells and thermocouples in the bottom of the reactor were exposed to hydrogen sulfide which added another failure mode from sulfidation attack. The temperature in this region was approximately 1800°F.

To alleviate the various failure mode problems, a new thermocouple and well assembly was designed utilizing off-the-shelf components. A diagram of a typical assembly identifying the major components is shown in Figure 2. This unit was designed to incorporate "change-on-line" feature and is able to accommodate a thermocouple longer than is required for the unit. This means that a spares inventory of only one or two sizes has to be maintained rather than an exact replacement size stock for each particular location. The major highlights of this design are:

- Use of an ungrounded W-5%/W-26% thermocouple with a disilicide

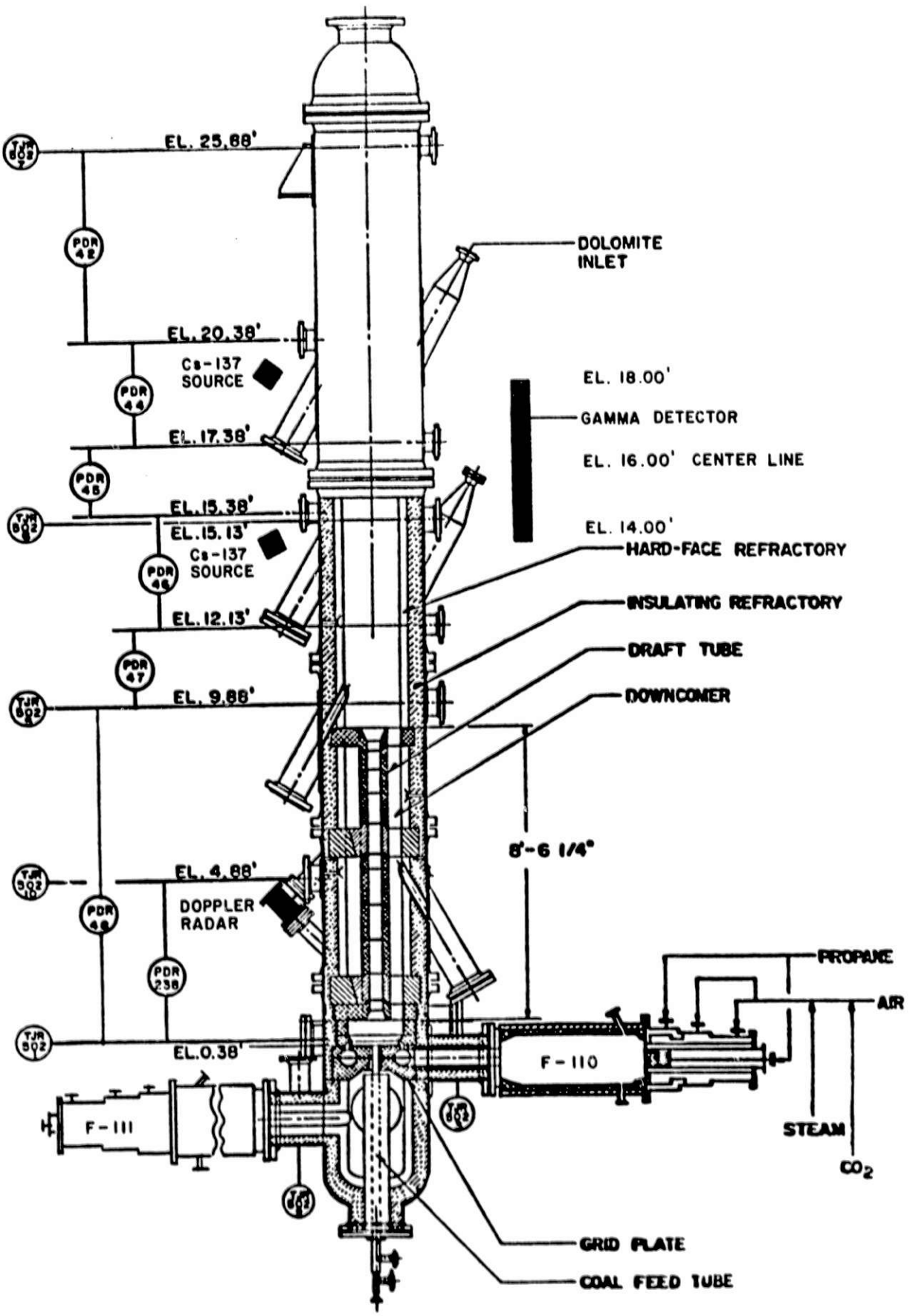


Figure 1 Devolatilizer Reactor Showing Process Instrumentation

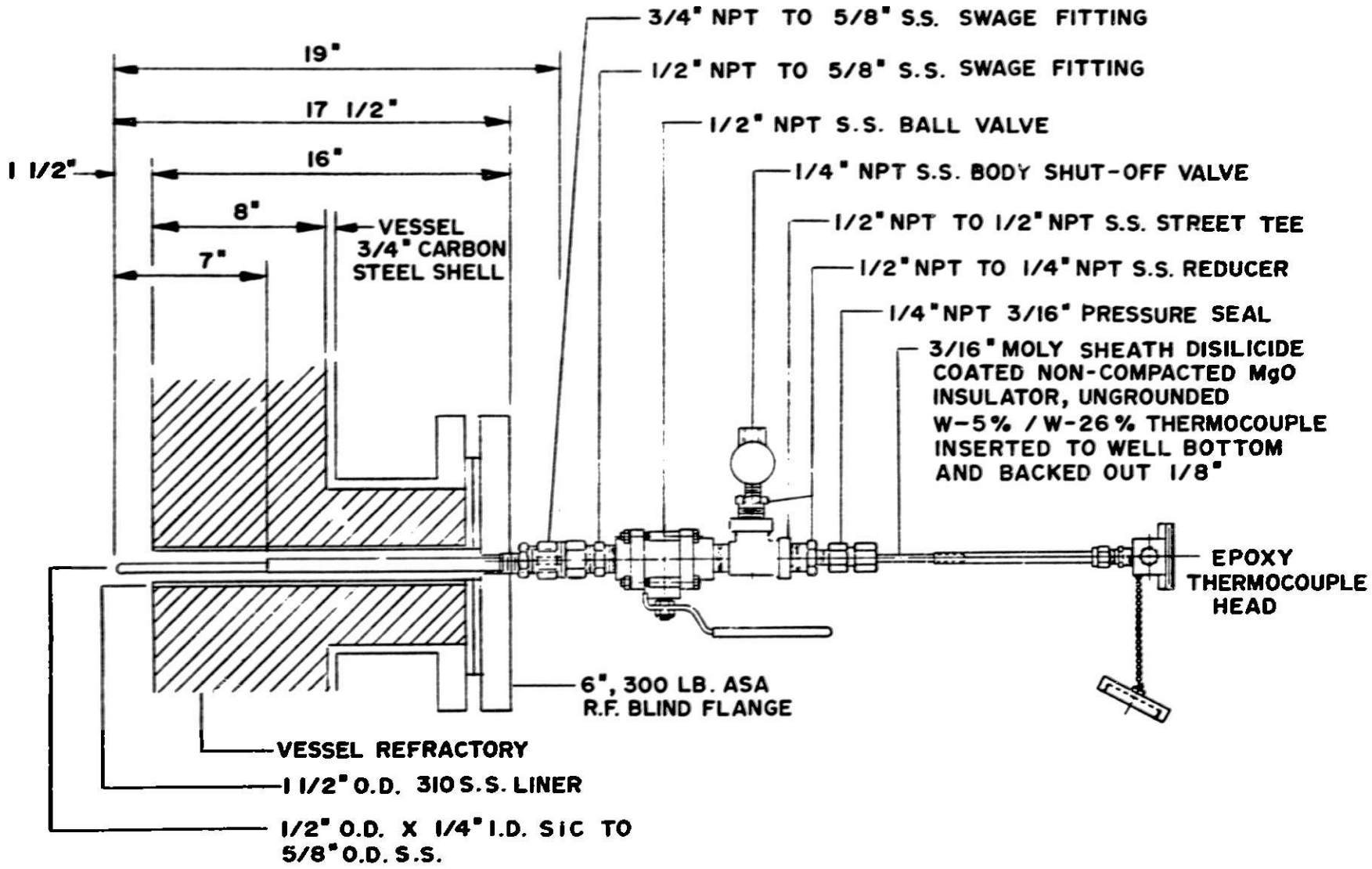


Figure 2 Schematic of a Change-On-Line W-5%/W-26% Thermocouple/Wall Assembly

coated molybdenum sheath and a non-compacted magnesium oxide insulator. The ungrounded junction eliminates failure due to differential thermal expansion between the thermocouple and sheath.

- A silicon carbide and stainless steel tube well to replace the Hastalloy-X. Silicon carbide resists oxidation up to 2500°F and is not subject to sulfidation attack.
- Inclusion of a "block and bleed" assembly to block off the well assembly when removing the thermocouple with the reactor at high pressure and temperature. The assembly consists of two stainless steel valves, one a block and one a vent, and a high pressure sealing gland. The stainless steel vent valve is used to check the integrity of the well before the thermocouple is removed.

Satisfactory performance was obtained from the new design. Records were maintained of the thermocouple/well performance during hot testing of the reactor. Some actual operating times of a few of the wells and thermocouples are tabulated in Table I.

TABLE I - PERFORMANCE CHARACTERISTICS OF NEW THERMOCOUPLE/WELL DESIGN

Thermocouple Location	Hot Test Running Time (Hours)	Max. Temp. Exposure
TJR-502-1 (above grid plate)	550 (still operative)	1800°F
TJR-502-2 (Fill outlet)	675 (still operative)	2400°F
TJR-502-6 (fluid bed region)	675 (still operative)	1500°F

It may be noted at this point that a few of the Hastalloy-X wells were left in the lower temperature zones of the reactor vessels for further study. The change-on-line feature was added to these thermocouples which include TJR-502-6, above.

Since the above modifications were incorporated, only one major problem remained. The problem was mechanical breakage of the thermocouples due to rough handling. Mechanical supports were designed to provide extra support on the cantilever section of the thermocouple protruding from the pressure seal, and breakage has been substantially reduced.

FLAME MANAGEMENT AND DETECTION

Operation of the devolatilizer without the use of the gasifier required the use of two synthesis gas generators. These units are designated by F110 and F111 on Figure 3. The F110 generator provides heat and fluidization gas to the downcomer. F111 provides heat and fluidizing gas to the draft tube. Both generators are designed to produce oxidizing gases (carbon dioxide, water, oxygen, and nitrogen) or reducing gases (carbon monoxide, hydrogen, nitrogen) at back pressures of 0 psi to 275 psi and with exit flame temperatures in excess of 2200°F.

Many problems were encountered with the "as-built" burners and controls, but only the problems associated with flame management will be discussed. Circuit details will be kept to a minimum and only the problems and solutions encountered in making the system operable will be highlighted.

As with any fuel/air fired burner system, a method of safely detecting a loss of flame and the follow-through of fuel and air safety valve shutoff was required along with a burner repurge prior to a safe ignition. The heart of the "as-built" flame management system contained an ultraviolet light (UV) detector mounted on the top viewport with the flame control relay box in the control room 300 feet away. Table II lists the problems encountered with this configuration along with various system and component changes made in order to solve them.

This combination of changes or problem solutions finally resulted in the most successful results for the flame management system. The burners were successfully operated without nuisance flame failures for many hundreds of hours of devolatilizer testing. Figure 4 shows a simplified block diagram of the finalized design. It was noted that upon a flame failure, the worst case temperature decay on the exit gas thermocouple was approximately 5°F/second from an initial temperature of approximately 2000°F. The low temperature switch was set at a locked set point of 50°F to 100°F below the steady-state flame temperature and required a manual reset to activate the control when the temperature was above the set point. Provisions were made to be able to reset the IR programmer or the low temperature switch (TSL) if either unit dropped out and no flame loss was visually observed. During start-up, the flame management operated on the IR system only.

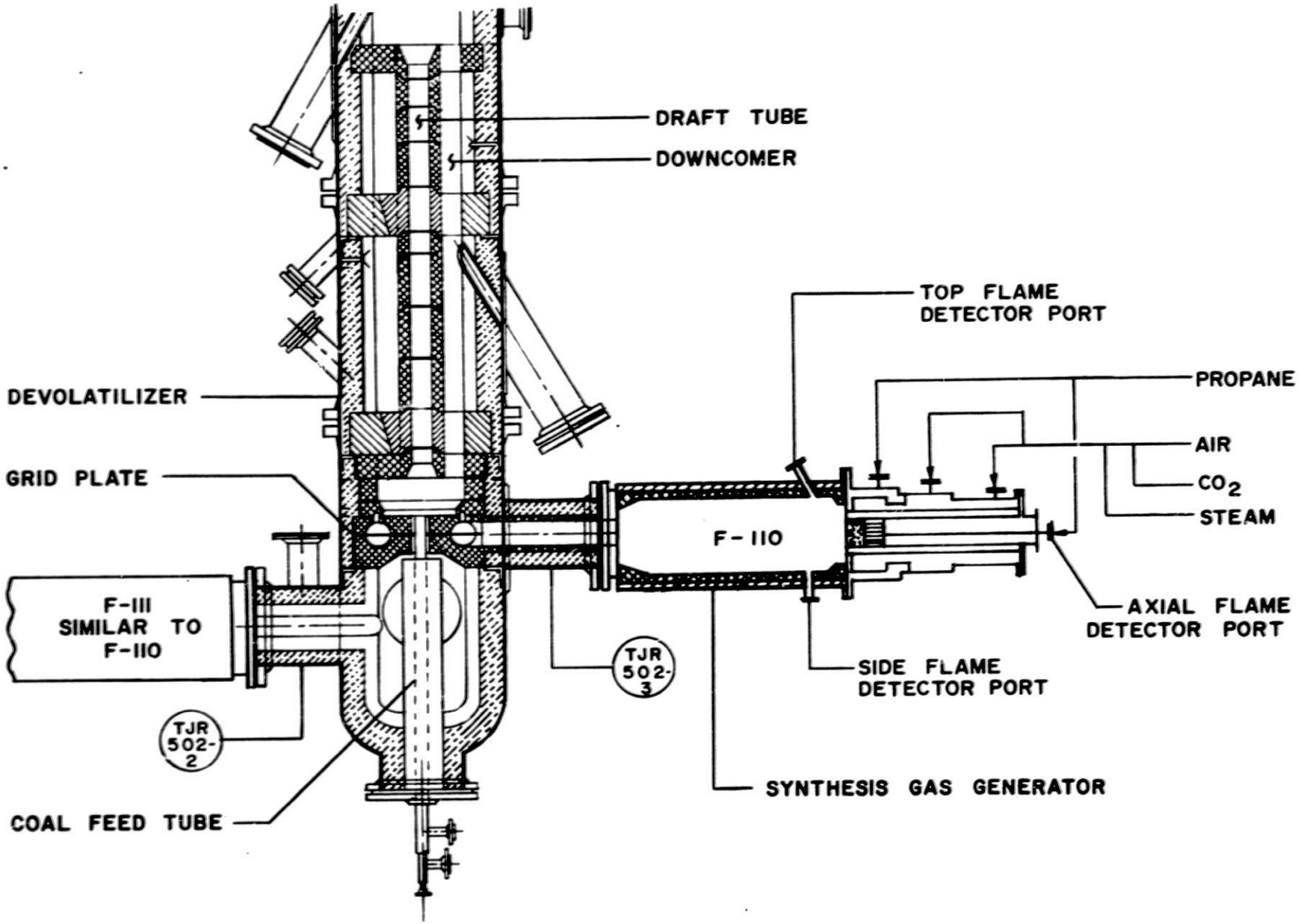


Figure 3 Simplified Synthesis Gas Generator Configuration

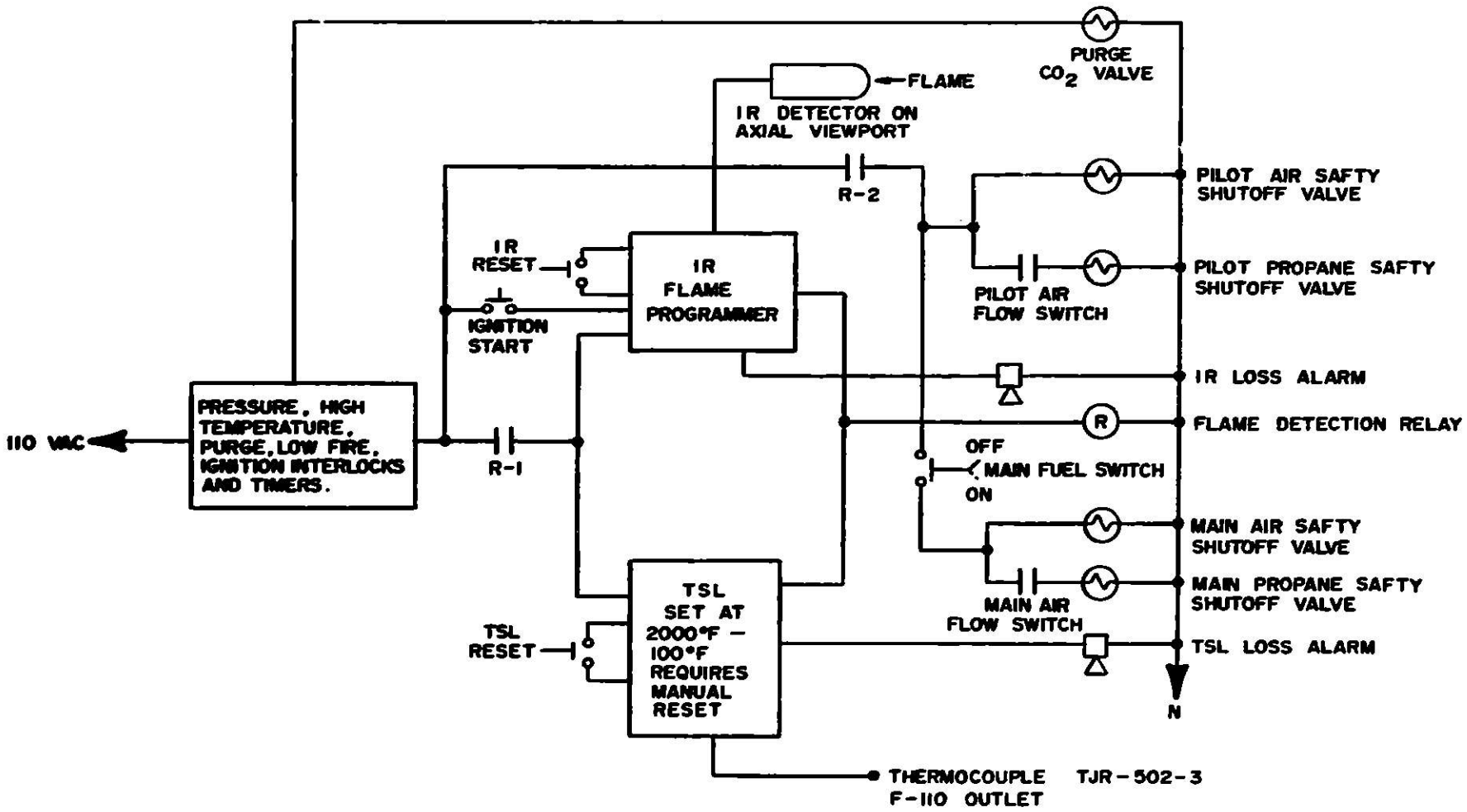


Figure 4 Simplified Schematic of Flame Management System

TABLE II - FLAME MANAGEMENT PROBLEMS AND SOLUTIONS

Weak UV flame signal below 50 psig system pressure at oxidizing conditions.	• Located flame programmer closer to detector in a purged enclosure. • Added a parallel UV detector on side viewport for signal enhancement. • Changed Pyrex viewports to optical grade quartz.
Inadequate UV signal at more than 100 psig system pressure. Strong infrared (IR) signal indicated.	• Added an axial viewport for UV detector. • Added an IR detector on top viewport with its flame programming logic in parallel with the UV programmer to provide an either-or capability. Loss of both IR and UV were required for burner shutdown.
Nuisance shutdowns from "dirty" flame (carbonaceous) obscuring top viewport during startup. No UV present at system pressures over 100 psig.	• Removed UV detector and programmer and added IR detector at axial viewport for startup with relay to switch to top detector after burner operated at steady-state conditions. • Operated from axial IR detector only.
Continued miscellaneous nuisance shutdowns from dirty flames and possible saturation of IR detector due to hot refractory viewed from axial viewport.	• Added a low temperature switch utilizing burner outlet thermocouple in parallel with the IR flame programmer. Flame failure shutdown required both loss of temperature and loss of IR.

In operation, the burners were ignited and brought to temperature solely on the IR flame detector and programmer. When steady state temperatures were reached above the TSL set point, the TSL was reset. Now the flame management operated with "either-or" logic for which a loss of both IR and a drop in temperature were required for shutdown. Independent alarms were added in the event that the temperature dropped below the TSL setting and the IR remained active or if a loss of IR occurred with no temperature drop. The TSL essentially was used to "fine tune" the flame management control at the operating point.

SOLIDS FLOW MEASUREMENT AND CONTROL

Three types of solids flow measuring systems are used at the PDU. Belt weighers, the most accurate, are used to weigh batches of coal, char, or dolomite from storage bins for transfer to feed hoppers. Speed controlled starwheel feeders, the least accurate, are used for feeding solids from lock hoppers to pneumatic conveying lines. Lock hoppers with strain-gage load cells are used for continuous monitoring of feed rate to the reactors or product collection rates from cyclones and reactors. No in-line devices are currently used.

The major problem with the starwheel feeders is the uncertainty in the amount of material that the feeder handles. Although the feeder revolution rate is known and the feeder pocket volume is known, the pockets are not uniformly filled. Particle size, moisture content, and other variables affect the feeder mass transfer rate for a given revolution rate. On the other hand, once a constant speed is established for a given material, the feed rate can readily be controlled at a constant rate. The starwheel feeders are, therefore, used for solids flow rate control but the set point is established on the basis of lock hopper load cell measurements rather than on starwheel feeder calibrations.

A typical lock hopper arrangement is shown in Figure 5. In this series arrangement, the lock hopper closest to the reactor is operated continuously at system pressure. It either feeds or accepts a continuous flow of solids. The hopper furthest from the reactor cycles from atmospheric to system pressure as each batch is received and discharged. The inboard hopper is mounted on three strain-gage load cells which are electronically summed and monitored in the control room.

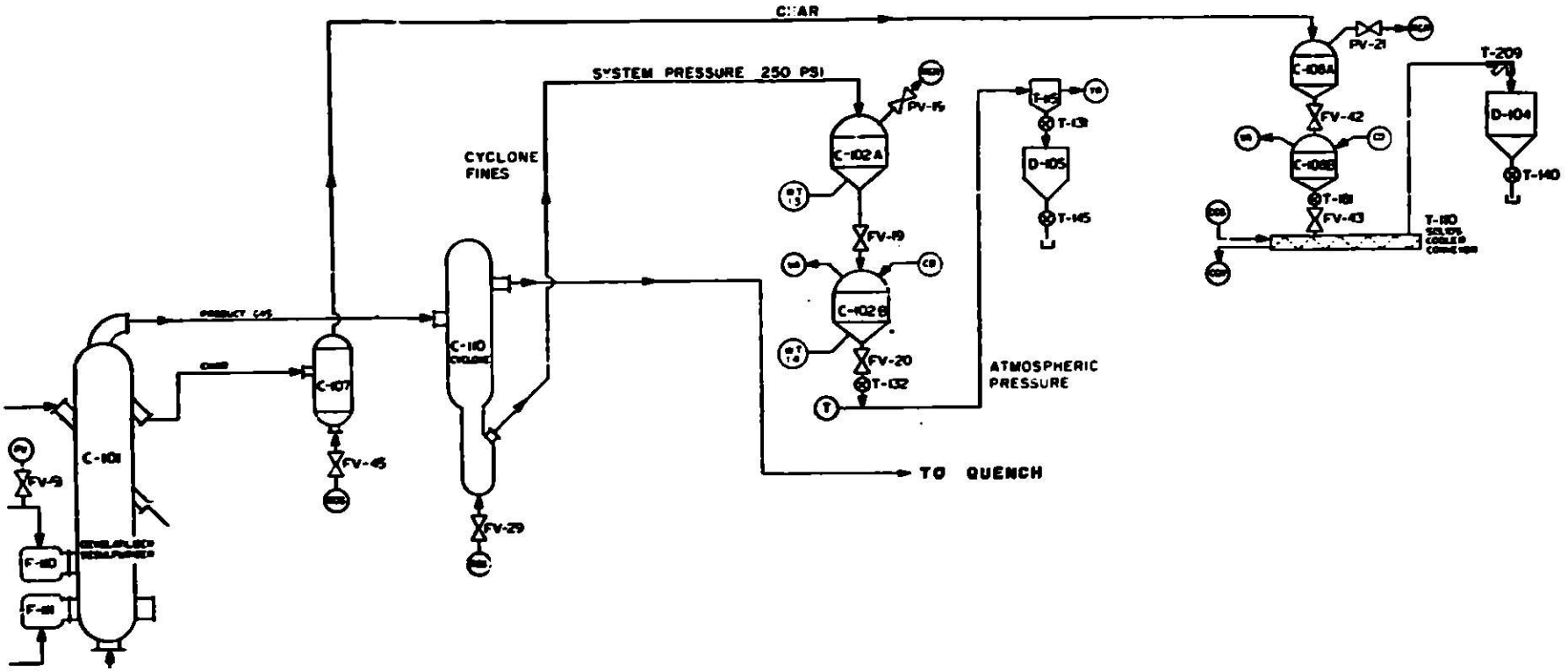


Figure 5 A Typical Lock Hopper System Showing Load Cell Instrumentation

During plant startup, problems were noted with the lock hopper load cell arrangement. The weight cell instrumentation was calibrated and tare adjusted with the vessels empty at atmospheric pressure. When the hoppers were pressurized, mechanical restraints existed between the two series lock hoppers due to rigid piping. In addition, pressurization and vent piping to the lock hoppers provided further resistance to movement. As the vessels were pressurized, both axial and transverse stresses were imposed on the load cells. This added a false weight to the load cells and, in some cases, over-ranged the instrumentation.

Most of the problems were corrected by eliminating the mechanical restraints in an attempt to make the hoppers free floating regardless of forces generated by internal pressure or external forces. Expansion joints were installed in critical areas above and beneath each lock hopper and in connecting piping. A modification was also made in the tare adjustment controls to permit a wider range of tare adjustment during the start-up phase. In practice, the load cells are calibrated at atmospheric pressure with no material in the hoppers. When the system is pressurized to a system pressure of 230 psig, the tare control is adjusted to show an indicated weight of zero in the control room. Filling of the lock hopper and continuous solids weight monitoring is then accomplished using the new zero offset.

The operation of the lock hopper load cell systems have proven to be quite reliable using the approach described. Only one additional operational modification has been required. Additional stresses were imposed on the cells as a result of thermal expansion of piping and vessels during the transfer of hot solids from the cyclones and reactors. This problem was overcome by controlling the transport gas flow and temperature used for conveying the solids. With a constant temperature on the lock hopper, the thermal stress loads can easily be tared.

INTERNAL SOLIDS FLOW RATE MEASUREMENT

In the Westinghouse devolatilizer, char recirculates at 0 to 2 fps at 230 psig and 1800°F. No known instrumentation is available that is capable of measuring the internal recirculating solid flow rate in fluidized bed reactors. A Doppler radar system was developed by Westinghouse for this purpose

and was tried with limited success. This device was designed to measure the average velocity of the char in the downcomer section of the devolatilizer under actual hot operating conditions with a velocity detection range of from .08 to 2.0 fps.

The theory of operation is as follows: a 10.5 GH_z signal is transmitted and the back scattered radiation from the moving particles is compared to the transmitted signal yielding a frequency shift related to the velocity by the basic equation:

$$v = \frac{fK}{\cos \theta} \qquad (1)$$

in which v = velocity of particles (in/sec),

f = beat frequency output of transciever (CPS),

θ = angle between the moving particles and transmitter, and

K = calibration factor.

A laboratory set-up of the system was tried with successful results on a Plexiglas mockup containing sand or char moving at a controllable velocity. The transceiver consisted of a 100mw, 10.5 GH_z Doppler radar unit, along with an isolation amplifier, pre-amplifier, filter, and a counter preset to read directly in in/sec. Eleven inches of refractory along with a quartz viewport were inserted between the Plexiglas and the transceiver was aligned at a 45° angle with respect to the flow of material in the simulated downcomer. The small 30mv electrical signal containing f was fed into a unity gain isolation amplifier to minimize noise. This signal was then amplified by the pre-amp to a usable level and filtered. Scale factors were programmed into the preset counter and the readout obtained in in/sec. Results of the tests indicated that the unit could be successfully calibrated by adjusting gain and counter trigger level to yield a readout within $\pm$20% of actual velocity near the inner wall of Plexiglas. Attempts to calibrate by adjusting gain and trigger level and looking for an inflection point of f yielded a $\pm$40% accuracy.

Based on these laboratory results, the unit was installed on the devolatilizer reactor using a special purged housing to meet electrical requirements of a Class I, Division 2, Group D hazardous area classification.

Figure 6 is a photograph of the unit in place. Figure 7 shows the physical arrangement as well as the block electrical diagram.

Poor results were obtained in the first tests of the unit in the field. Two problems were encountered:

- Additional reactor refractory previously not included in the lab calibration had to be removed and replaced with insulating blanket to alleviate the signal attenuation.
- Moisture condensed on the inside of the viewport flange had to be eliminated by purging the flange to assure good signal transmission.

Following these changes (shown in Figure 7), the unit was tried during an actual hot test program of coal devolatilization with limited results. Test data indicated that the velocity in the downcomer was lower than the anticipated velocity of 1 inch/sec to 24 inches/sec. This fell below the resolving capability of the transceiver (1 H_Z to 1000 H_Z) and steady-state velocities were not detected. The system did detect transient velocities of char filling up the reactor during startup. These velocities were essentially the terminal velocities of the char particles and were an order of magnitude higher than the steady-state conditions. Velocities were in the neighborhood of 16 inches/sec.

Figure 8A shows the ambient noise level in the empty reactor detected by an oscilloscope at the output of the filter. Figure 8B indicates hot char particles falling into the reactor during bed filling operations. The fundamental frequency is approximately 20 H_Z and relates to a velocity of 16 inches/sec from equation (1). The ragged components of the waveform are caused by the inherent background noise and by reflections from particles deeper in the reactor.

Further development is required to make the system a viable and reliable piece of instrumentation. Some design criteria for these developmental efforts include:

- The signal should be able to penetrate the stagnant or slow moving particles at the wall and measure the more active region of the downcomer.

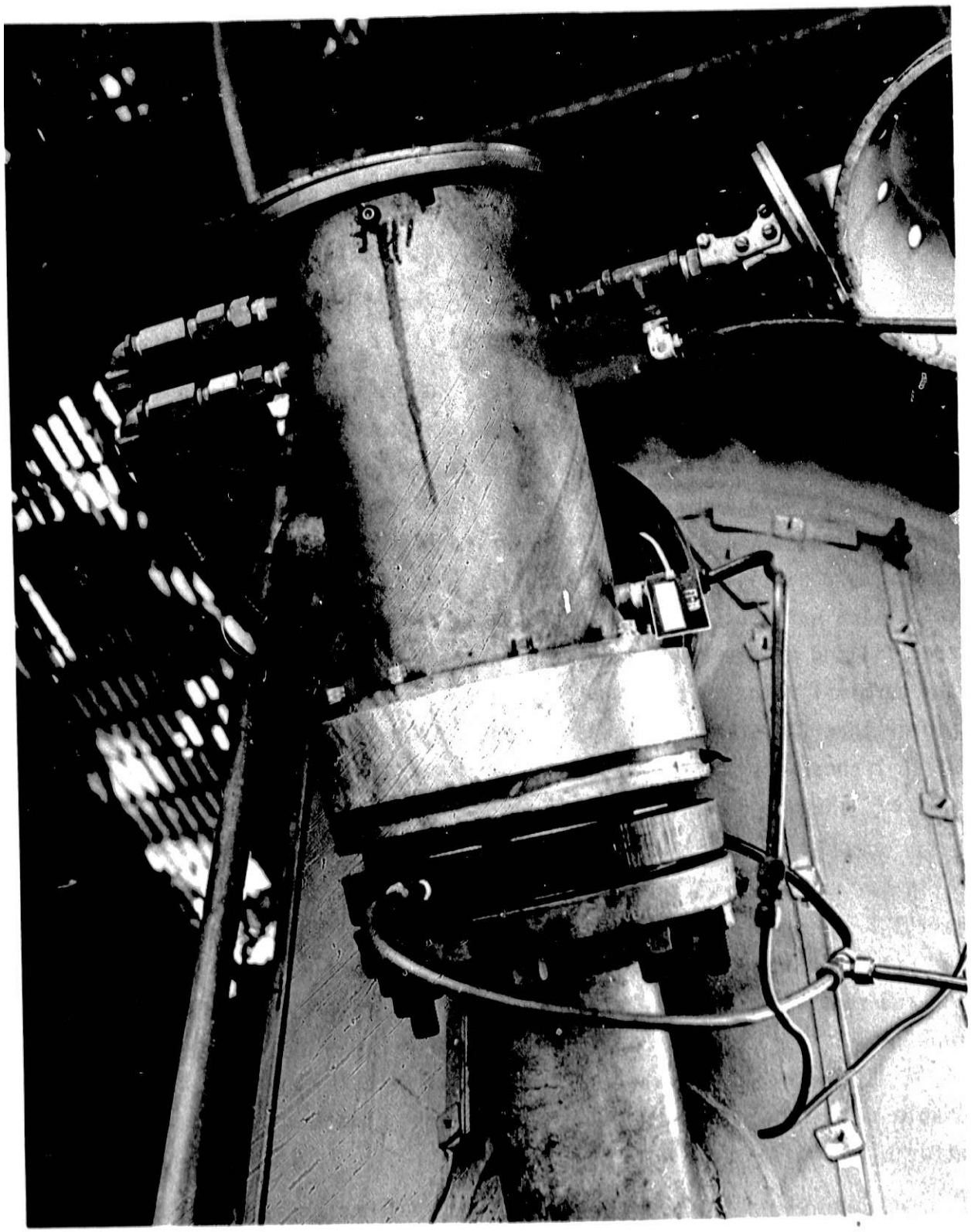


Figure 6 Doppler Radar Unit Installed on the Devolatilizer

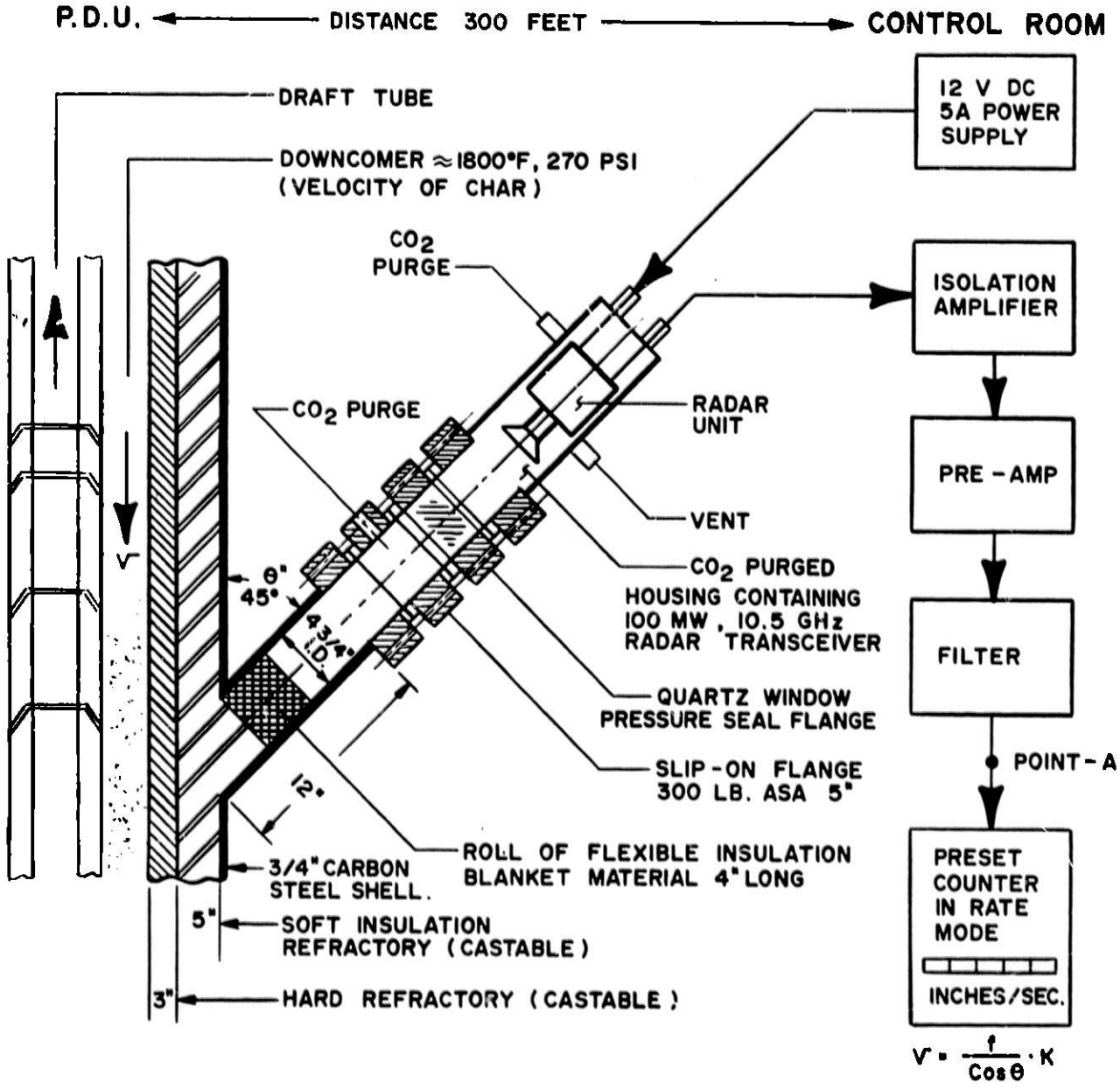


Figure 7 Doppler Radar Installation and Electronics Block Diagram

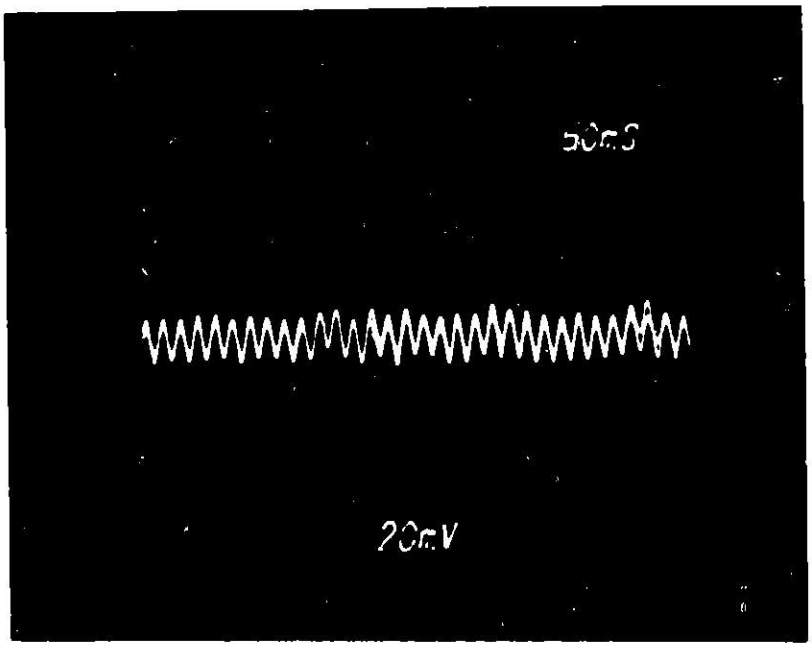


PHOTO-A BACKGROUND NOISE

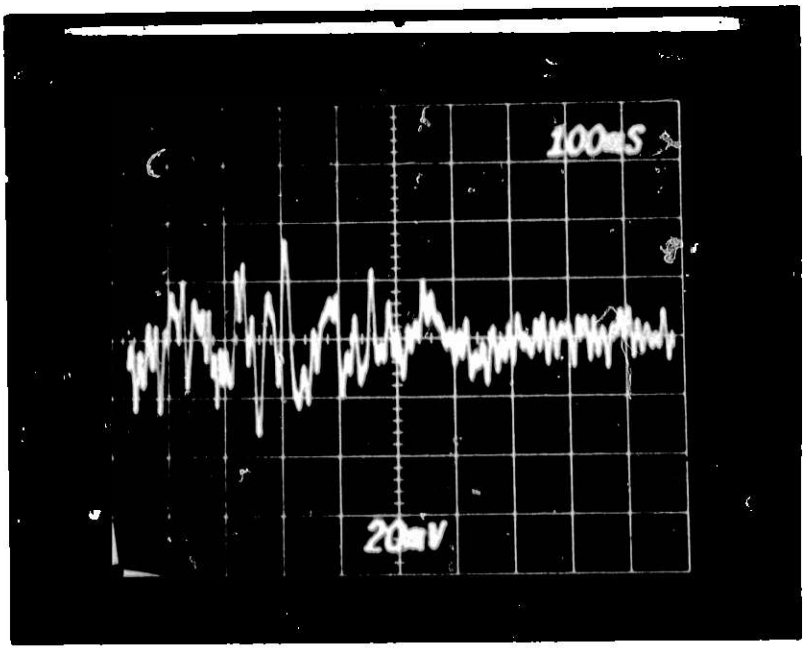


PHOTO-B PARTICLE MOVEMENT

Figure 8 Oscilloscope Photos of Actual Radar Signals During Hot Coal/Char Test

- Calibration of the system should be insensitive to signal strength changes due to aging of the transmitters, changes of attenuating variables, reflectivity changes from different char/dolomite mixtures and densities of materials.
- A high signal-to-noise ratio must be achieved.

FLUIDIZED BED LEVEL AND DENSITY MEASUREMENTS

Both the devolatilizer and gasifier are heavily instrumented with electronic differential pressure transmitters as the prime instrumentation for determining vessel bed heights and bed densities. The wall static pressure probes shown in Figure 9 are used to measure the bed pressures. These probes are generally connected to a differential pressure transmitter to measure the pressure drop across a given reactor length. These differential pressure measurements together with the length are used to calculate the fluid bed densities and bed height. Fluid bed densities are calculated by the equation:

$$\rho_B = 144 \frac{\Delta P}{\Delta L} \qquad (2)$$

where ρ_B = fluid bed density, lb/ft^3,

ΔP = measured differential pressure, psi,

ΔL = length of bed between probe locations, feed.

The bed height is determined by the model shown in Figure 10.

The design of this pipe pressure probe features the use of clean, dry carbon dioxide purge gas injected upstream of the pressure transmitter impulse line. This purge gas is used to keep the pipe clear of migrating particulates that could locally accumulate and create plugs. The velocity range for these purges is maintained between 0.5 and 1.0 fps which is well below saltation velocity for most of the particles within the fluid bed. The intent of the purge flow is not to transport particles out of the pressure probe but to provide a slightly higher pressure region at the exit of the pipe. The gas exiting the probe probably appears as a bubble extending into the bed. Calibrations indicate that no appreciable error in pressure measurement is experienced at these purge velocities.

Plugging problems were experienced early in the operational phase. These plugs were attributed to improper purge initiation procedures and lack

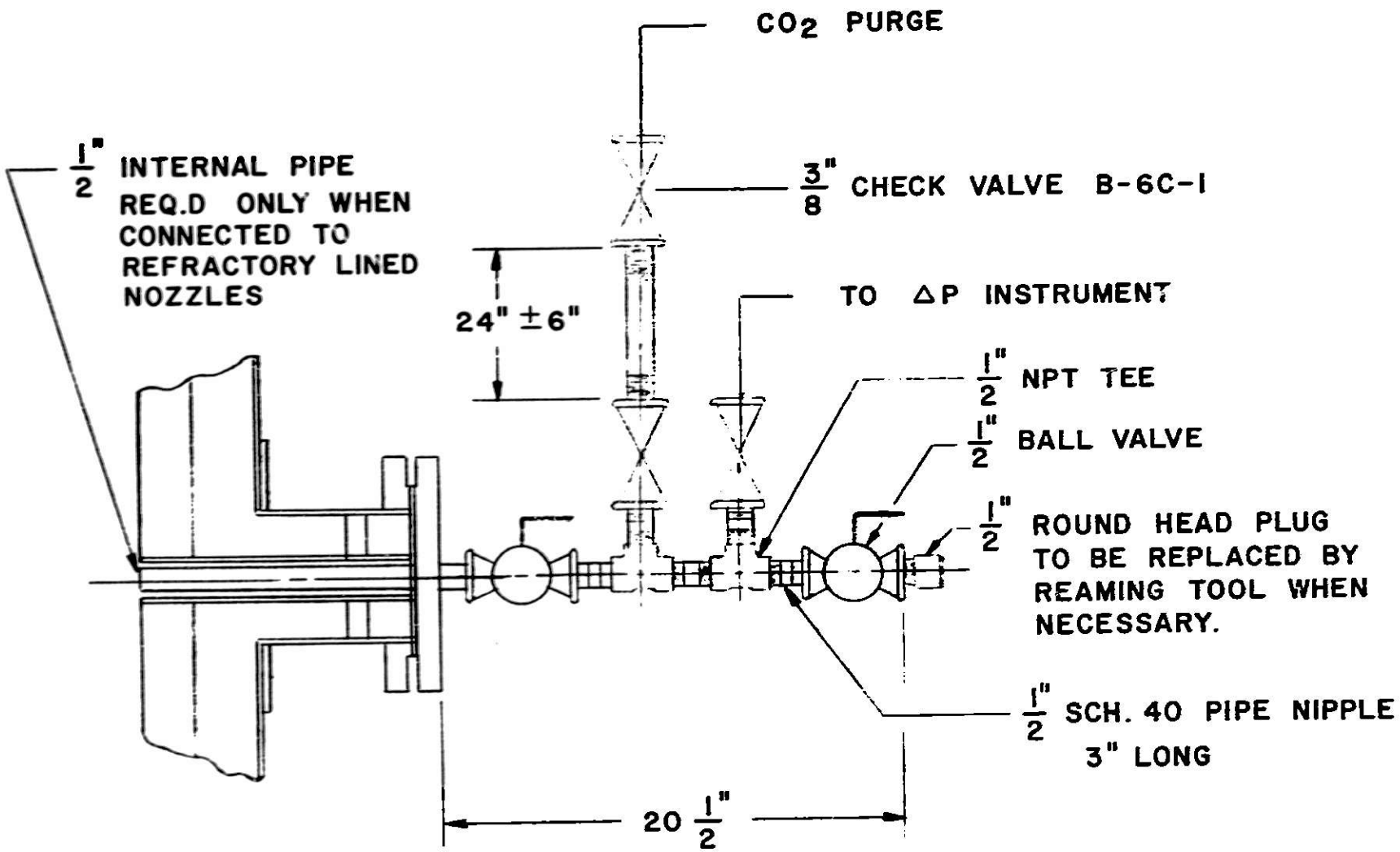
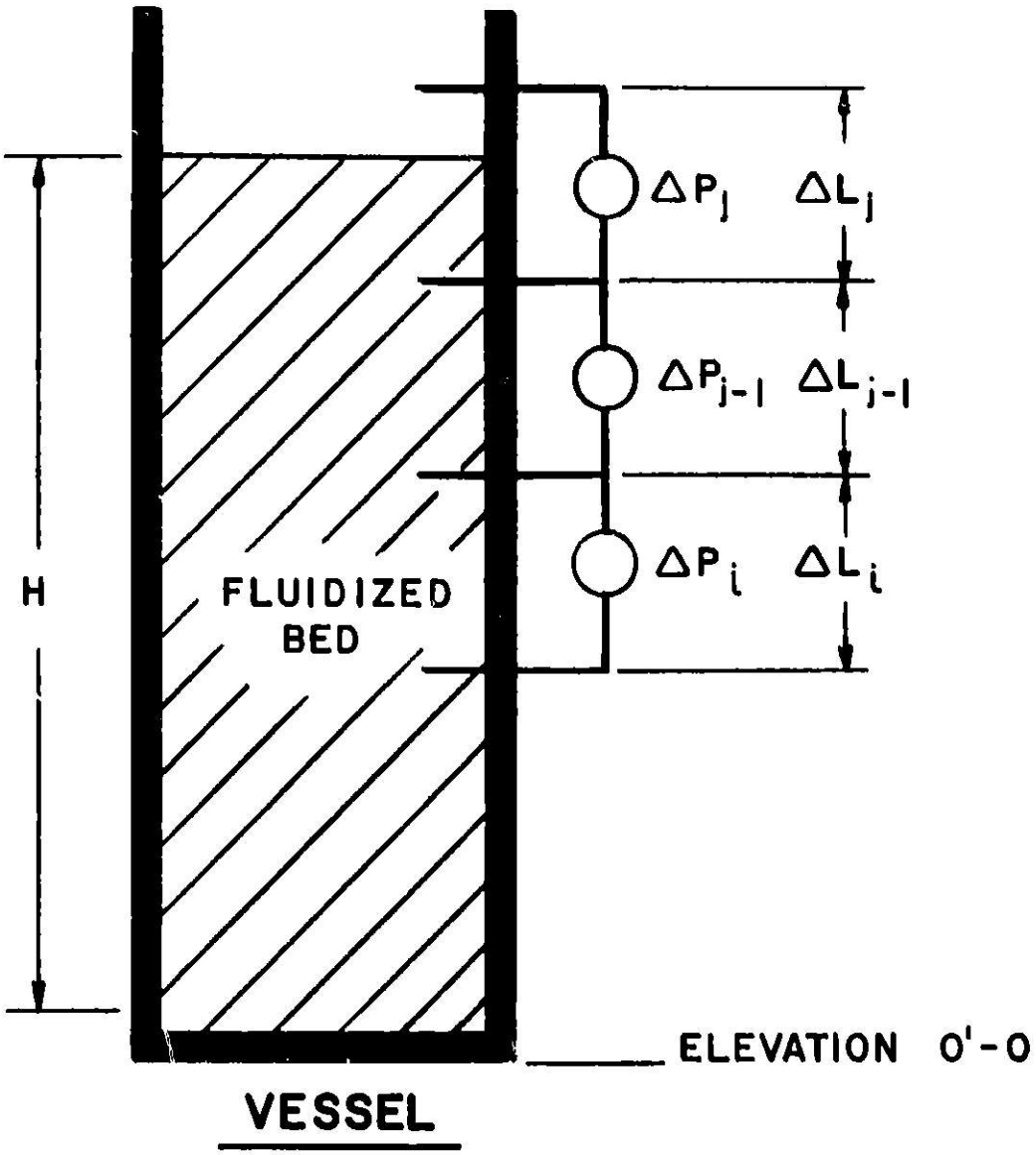


Figure 9 Wall Static Pressure Probe



$$\rho_{B_i} = 144 \frac{\Delta P_i}{L_i}$$

$$H = \sum_{i}^{j-1} L_i + \frac{\rho_{B_j}}{\rho_{B_{j-1}}} \Delta L_j$$

ρ_{B_i} = INCREMENTAL BED DENSITY, LB/FT^3
ΔP_i = INCREMENTAL PRESSURE DROP, PSI
ΔL_i = INCREMENTAL LENGTH BETWEEN TAPS
H = TOTAL BED HEIGHT, FT

Figure 10 Fluidized Bed Model for Calculating Bed Density and Bed Height

of isolation from the vessel while blowing down pressure transmitters to pneumatically clear plugs. In cases where plugs could not be pneumatically cleared, they were cleared utilizing the rod-out tool shown in Figure 11. This tool is attached to the outboard valve and tightened to provide the pressure containment seal between the reactor pressure and atmosphere. Once the tool is attached, the outboard ball valve can be opened and the shaft rod inserted to clear the plug. A drill at the end of the shaft rod is provided in cases where a drilling action may be required.

Along with the differential pressure instrumentation, a nuclear densitometer system was installed for evaluation as a possible bed level indicator. This system worked satisfactorily and a good correlation of gamma radiation penetration was made with respect to the bed heights obtained from differential pressure probes.

The system consisted of two Cs-137 gamma radiation sources of 1 Curie strength each, a 4-foot long radiation detector, and a signal process amplifier and recorder. One source was mounted at an elevation of 18 feet with respect to the bottom of the devolatilizer with the other at a 14 foot elevation. The detector was mounted 180° from the sources around the perimeter of the vessel with its longitudinal center at 16 feet.

Initial calibration of the system to obtain the 0% and 100% end points was done as follows: With the reactor empty and the sources open, the amplifier was adjusted to zero percent output to simulate full gamma penetration. Likewise with the reactor empty and sources closed, the amplifier was adjusted for 100 percent output to simulate full gamma absorption. This initial calibration was done for purposes of repeatability in that the material did not have to be handled in the reactor during subsequent periodic calibrations.

During actual hot coal testing of the devolatilizer, bed heights were obtained and plotted against the output of the amplifier for different materials. Figure 12 shows the actual data obtained for Indiana and Pittsburgh seam coals as compared with bed heights calculated from differential pressures. The data obtained proved that the system can be used as a viable method of determining bed height externally by using gamma radiation equipment. This system can be incorporated into a working closed loop control to control the reactor bed level.

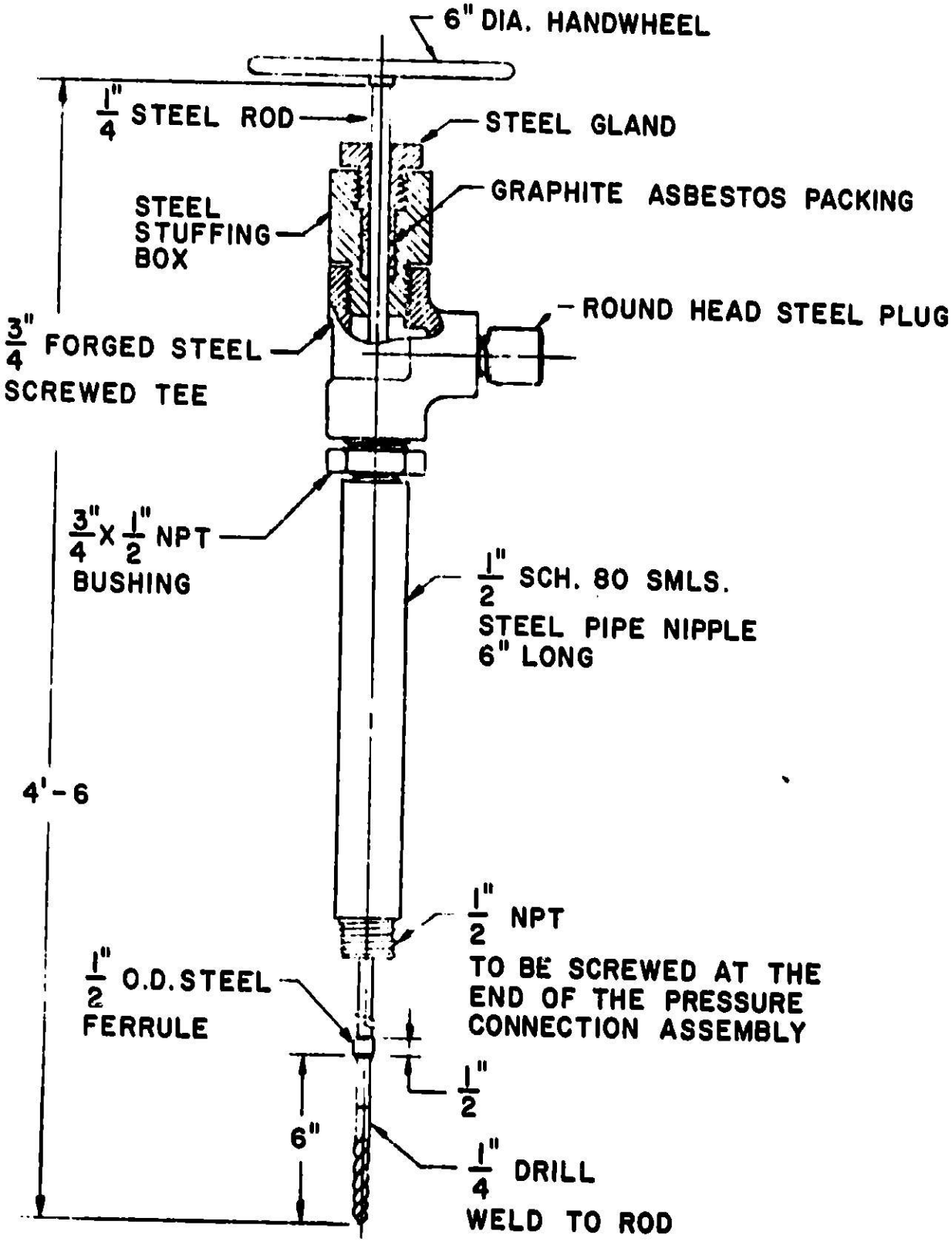


Figure 11 Rod Out Tool

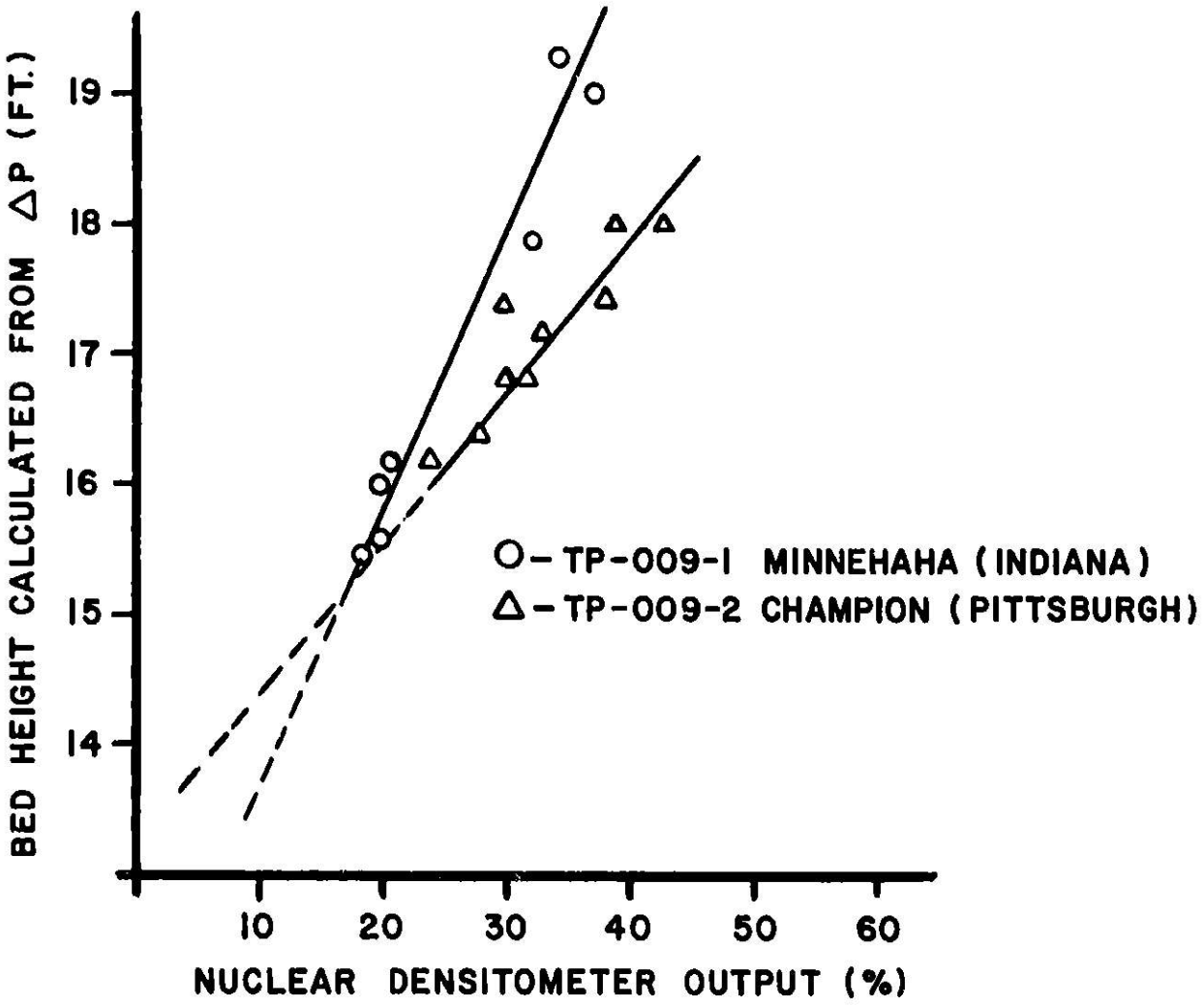


Figure 12 Comparison of Bed Height Calculated from Differential Pressures with Nuclear Densitometer Output

COMBUSTOR TEMPERATURE MEASUREMENT

In the early tests of the PDU Gasifier, an attempt was made to try to measure the combustion zone reaction temperature with an infrared radiation sensing optical pyrometer. Since no entrance port into the reactor was available directly above the air tube (expected combustion zone), it was thought that the zone could be viewed by looking directly up the 2-1/2-inch diameter, 15 foot long air tube. An optical grade quartz pressure seal viewport with an internal purge to keep the inside surface of the window clean was used. In theory, it was felt that the actual char combustion would take place at the interface of the air stream and char. Since the air tube contained only gas and was free of particulates, the combustion zone would be in plain view.

This scheme was tried and abandoned because condensed moisture and dirt fell into the viewport area during the system pressurization and hot air dryout portion of the test in spite of the CO_2 purge flow on the viewport. The viewport became totally blocked before the combustion of char took place.

Another attempt was made to measure the combustion zone temperature via two adjustable length type K thermocouples routed up the air tube inside protective 3/8-inch O.D. 310 stainless steel tubing wells. To date, the lengths of these units have been adjusted in an attempt to find and measure the combustion zone temperature. With the thermocouples extending 18 inches above the air tube, the measured temperature appears to be near combustion temperature. However, more work will have to be done to verify that the true combustion zone temperature is being measured.

SAMPLING & ANALYSIS OF PRODUCT GAS STREAMS

On-line monitoring of gas composition has served the two major objectives of characterizing the product gas in terms of its calorific value and generating analytical data for computing plant heat and material balance. Gas characterization hardware used at the PDU can be divided into two subsystems; namely, sample preparation and delivery trains, and gas analysis. Several operational problems in these subsystems were encountered during the initial PDU devolatilizer tests. A continual development effort has been pursued to modify individual components in these subsystems so as to meet the severe requirements associated with hot gas sampling and analysis.

whereas the polar gases (CO_2 and H_2S) elute out of a Porapak N column. The analog signal from the detector bridge is input to an integrator which digitizes peak areas. This signal is then fed to a PDP-11 computer which identifies gaseous species of interest and computes the percentage composition. The total cycle time is 8 minutes per stream.

Operating experience with this chromatograph has shown that, in most cases, instrument downtime can be ascribed to the presence of mist and entrained solids in the sample gas. These impurities deposit in the sampling loop and cause perturbations in the flow of carrier gas through the columns. Moreover, the presence of liquid slugs has, on occasion, led to column deterioration and hence loss of chromatographic separation. These problems have been corrected by the expedient of quenching the gas and removing condensables and particulates in gas filter racks.

Calibration drift and precision errors are estimated by a statistical method employing data from calibrations performed prior to and following a plant test run. These errors are within 1-2% of actual gas compositions for all gases except hydrogen which experiences a calibration drift of up to 10%. This is due to the lower sensitivity for hydrogen estimation when using a spiked helium carrier gas. Plans are underway to incorporate a dual carrier gas arrangement which will enable an independent estimation of hydrogen on an argon carrier.

The characterization of product gas is not complete without an estimation of its water, oil, and tar contents. As described earlier, the sample preparation system separates these constituents from the gas delivered to the chromatograph. Hence to fill in this analytical need, a special technique was developed to characterize hot product gas as to its condensables content.

The apparatus used for this technique is called a total condensables train. Hot gas is periodically sampled off a nozzle and chilled in a glycol-cooled jacketed condenser. The condensate is collected in a catch pot equipped with a baffle plate and a coalescing type ceramic filter. Additional moisture is adsorbed in a desiccant pot before the gas is metered for total throughput and flow rate. The condensate can then be analyzed for determination of percentage yields of water, paraffins, and aromatics.

The PDU program will shortly enter an operations phase where the devolatilizer and gasifier are run as an integrated unit. This will call for additional demands on the present sampling and analysis hardware. Future plans include the acquisition of additional gas chromatographs to enable a rapid

turnaround of gas composition data.

Gas monitors with quick response features will be acquired to carry out special tasks pertaining to feedback process control and optimization. These include an on-line infrared analyzer to study the effect of steam/air feed ratios on CO and CO_2 content of the gasifier product and an H_2S analyzer to study the feasibility of in-situ desulfurization.

Acknowledgements

The authors wish to acknowledge the contributions of co-workers on this program who furnished material for this paper: S. P. Tendulkar, S. S. Kim, L. K. Rath, P. J. Margaritis, F. J. Wyant, E. F. Vandergrift, M. J. Arthurs and R. B. Mangold.

QUESTIONS AND ANSWERS

J. E. Macko

Westinghouse Electric Corporation

W. H. Marlow, Brookhaven National Laboratory

Q. Because of differential particle velocities in the turbulent flow, how can your radar Doppler velocitrometry be very useful for measuring flows of "particulate matter?" If you knew aerodynamic diameter and density distributions of particles and had gas flow well characterized beforehand, it might be possible.

A. You have to take these into consideration, and what we're looking for is an average velocity. When we had the mockup at the labs we actually calibrated the unit with some doping of the material, and clocked it. If you want to talk more about it later, I'd be glad to see you in the coffee area.

W. S. Su, Stearns-Roger

Q. Reason for radar probe with angles - downward or upward. How? Why?

A. Ideally, you'd want to look directly ahead at your moving particles, but since we couldn't we had the transmitter mounted on the 45° flange and attempted to measure the velocity of the material moving downward. There was no way we could put the unit on the bottom or the top of the reactor to measure the actual head-on velocity. We had two 45° flanges on the devolatilizer. It didn't matter which one was used.

If you looked at something moving, say on a vertical plane, and your Doppler radar is mounted at a 90° angle, you'll get zero, cosine of 90° is zero, so you have to monitor at an angle. Therefore, the flanges were installed on the reactor at a 45° angle.

A. Chaudhuri, Dorr-Olive, Inc.

Q. During a process run do you take a thermocouple out for replacement? What precautions are necessary?

A. Yes - The vent valve is partially opened to check the well for leaks. The packing gland nut is loosened and the unit is withdrawn slowly past the block valve. The block valve is then closed and the unit removed. The reverse is used to replace the unit.

A. Chaudhuri, Dorr-Olive, Inc.

Q. Do you do any rod out for debugging pressure tap during a process run? Any precaution necessary?

A. Occasionally, it is done under direct supervision of a shift supervisor and a procedure is followed outlining the method. I will gladly discuss the procedure with you later.

N. L. Kautsky, Stearns-Roger, Inc.

Q. A gas chromatograph readout may require 30 minutes to obtain results. Do you find a need for quicker analysis, and if so, what are your plans to obtain them?

A. With our system, there is about an 8 minute lag to obtain an analysis. At present, we have no plans to improve the time.

B. G. Liptâk, Liptâk Associates

Q. Could you elaborate on start-up problems? Purging to protect against unsafe conditions. etc.

A. I do not have enough time to discuss plant start-up problems. As far as the synthesis gas generators, a purge of the CO_2 occurs automatically prior to a trial for ignition and following a flame failure.

TEMPERATURE CONTROL IN THE EXXON FLUIDIZED BED COMBUSTION MINIPLANT

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ABSTRACT

Exxon Research and Engineering Company, under contract to the EPA, has built and is operating a pressurized fluidized bed combustion unit which is capable of burning up to 218 kg/hr of coal (480 lbs/hr). This unit is referred to as the Exxon fluidized bed combustion miniplant.

One of the major systems on the miniplant is the control system used to maintain a uniform fluidized bed temperature. The method of bed temperature control, which is applicable to many coal conversion processes, is based on adjusting the rate of coal injected into the combustor.

This presentation describes the temperature control system and the coal feed system. The performance of temperature control system and the associated coal feed system is also discussed.

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1. INTRODUCTION

The pressurized fluidized bed combustion of coal is a new combustion technique, which can reduce the emission of SO_2 and NO_x from the burning of sulfur-containing coals to levels meeting EPA emission standards. This is done by using a suitable SO_2 sorbent such as limestone or dolomite as the fluidized bed material. In addition to emissions control, this technique has other potential advantages over conventional coal combustion systems which could result in a more efficient and less costly method of electric power generation. By immersing steam generating surfaces in the fluidized bed, the bed temperature can be maintained at low and uniform temperatures in the vicinity of 800 to 950°C. The lower temperatures allow the use of lower grade coals (since these temperatures are lower than ash slagging temperatures), and also decrease NO_x emissions. Operation at elevated pressures, in the range of 600 to 1000 kPa, offers further advantages. The hot flue gas from a pressurized system can be expanded through a gas turbine, thereby increasing the power generating efficiency even further.

In the fluidized bed boiler, limestone or dolomite is calcined and reacts with SO_2 and oxygen in the flue gas to form $CaSO_4$ as shown in the following reaction.

$$CaO + SO_2 + 1/2O_2 \rightarrow CaSO_4$$

Fresh limestone or dolomite sorbent feed rates to the boiler can be reduced by regeneration of the sulfated sorbent to CaO and recycle of the regenerated sorbent back to the combustor.

A diagram of the pressurized fluidized bed combustion and regeneration process is shown in Figure 1.

2. EXXON MINIPLANT

Exxon Research and Engineering Company, under contract to the EPA, has built two pressurized fluidized bed combustion units to study the combustion and regeneration processes. The larger of these units, the Exxon fluidized bed combustion miniplant is shown in Figure 2. The miniplant consists of a refractory lined combustor vessel with provisions for continuous feeding of coal and fresh sorbent and continuous withdrawal of spent sorbent. A refractory lined regenerator vessel was built adjacent to the combustor with provisions for the continuous transfer of spent sorbent from the combustor to the regenerator and the continuous return of regenerated sorbent to the combustor. The combustor vessel is 9.75 metres high (32 ft) lined to an internal diameter of 31.8 cm (12.5 in) and is capable of burning up to 218 kg/hr of coal (480 lbs/hr). Cooling coils in the combustor remove the heat of combustion and maintain the bed temperature in the operating range of 815 to

955°C (1500 to 1750°F). The maximum operating pressure is 1010 kPa (10 atm); the maximum superficial velocity is 3 m/s (10 ft/sec).

The following discussions will focus on one of the major control systems on the miniplant, e.g., the control system used to maintain a uniform fluidized bed temperature. This method of bed temperature control, which is applicable to many coal conversion processes, is based on adjusting the rate of coal injected into the combustor. As the temperature control is based on adjustment of the coal feed rate, the discussion will begin with a description of the coal feed system.

Information on the other control systems used on the miniplant can be found in EPA Report No. EPA-600/7-76-011, September, 1976.

3. COAL FEED SYSTEM

The coal injection system, originally designed by Petrocarb, Inc. and subsequently modified by Exxon Research is illustrated in Figure 3. The system provides for uninterrupted solids feed (a controlled mixture to coal and limestone) from the primary injector to the combustor while allowing intermittent refilling of the primary injector (193 kg operating capacity) when its charge is reduced below 102 kg.

Solids in the primary injector are continuously aerated at a controlled pressure above that in the combustor. They exit the primary injector through a 1.3 cm diameter orifice and are pneumatically conveyed by a controlled stream of dry transport air through an s-shaped 1.3 cm I.D. stainless steel pipe leading into the combustor. Load cells, located under the injector, are used to monitor solids feed rate. Rate of solids feed is automatically controlled in order to maintain a flow rate of coal sufficient to achieve a specific operating temperature within the combustor. This is accomplished through a series of controls involving the pressure differential between the primary injector and combustor, the injector pressure, and the transport air flow rate. Final entry of solids into the combustor is through a 1.3 cm I.D. probe located 28 cm above the fluidizing grid and horizontally extending about 2.5 cm beyond the reactor wall. The tip of the probe includes ten 0.79 mm diameter holes which surround the solids feed opening. They are used to continuously inject an annular stream of sonic-velocity air to assist penetration of the solids feed into the fluidized bed and alleviate any tendency of the probe tip to become blocked with bed solids.

Prior to the initiation of a refilling operation, the primary injector, the feed injector, and a pair of solids storage bins remain isolated from each other. When the load cells under the primary injector detect a solids loading of less than 102 kg, 91 kg of solids are automatically transferred from the pressurized feed injector without interrupting feed to the combustor. Refilling is usually completed in about 5 minutes. After refilling, the feed injector is again isolated from the primary injector, vented, and filled with solids from the storage bins. The feed injector is again isolated and repressurized to await repetition of another cycle.

Process air for the solids feeding system is provided by an auxiliary air compressor with a rated capacity of 200 SCFM at 200 psig (5.6 standard m^3/min at 1380 kPa gauge).

4. TEMPERATURE CONTROL SYSTEM

The miniplant combustor is operated at bed temperatures from 815 to 955°C (1500 to 1750°F), with temperatures monitored at many elevations within the combustor. The combustor temperature is primarily controlled by adjustment of the rate of coal injected into the fluidized bed.

A thermocouple in the lower zone of the combustor 47 cm (18 inches) above the fluidizing grid is used as the sensor to control temperature of the combustor, and the set point temperature at this location regulates the coal feed rate to the combustor.

As explained above, the coal feed rate to the combustor is regulated by the pressure differential between the primary coal vessel and the combustor - the greater the pressure difference, the greater the feed rate. A sketch of the arrangement is presented in Figure 4.

Temperature control is accomplished by a cascade type control loop using two controllers, one for temperature set point and another for ΔP set point. A deviation of the desired (set point) temperature from the actual combustor temperature causes a signal to be transmitted by the temperature controller to the ΔP controller. This error signal actually resets the set point of the ΔP controller so that a different ΔP will be established between the primary injector and the combustor.

This change in the pressure difference between the coal vessel and combustor causes a change in the solid feed rate which will tend to return the bed temperature to the desired (set point) value.

5. PERFORMANCE OF THE TEMPERATURE CONTROL SYSTEM

The fluidized bed combustion miniplant, as explained above, uses a common solids feed containing a specific ratio of coal and the limestone needed for desulfurization. Although both the coal and limestone are individually screw-fed at a preselected ratio through a blender into the feed injector, small variations in the specific coal to limestone ratio at any given time can be expected as a result of blending inhomogeneities. These variations in the specific ratio and inhomogeneities in the coal i.e., a localized concentration of ash, result in a variation in the measured solids feed rate to the combustor needed to maintain the set temperature. Measurements of the solids feed rate and the combustor bed temperature are recorded once a minute by the miniplant data acquisition system. During this interval of time about 3 kg of solids containing approximately 70 to 85% by weight of coal is being fed to the combustor.

Proper tuning of the controllers was necessary to achieve optimum reaction to system perturbations and to anticipate changes in bed conditions. This control system has performed very satisfactorily and provides excellent temperature control and response.

The $\sigma/\bar{X}$ values (standard deviation divided by the mean) for the combustor temperature at the set point and for the solids feed rate measured during two separate periods of a recent miniplant run are shown in Figure 5. The actual data points shown represent the average values and the associated standard deviation for a twenty minute sampling interval during which the values were measured once a minute by the miniplant data acquisition system.

The range in the fluidized bed temperature measured at the set point (47 cm above the grid) normally is $\pm 3°$ Celcius at an average temperature of 900°C. This corresponds to a $\sigma/\bar{X}$ variation of 0.3%. The observed variation in the solids feed rate necessary to achieve this set temperature is considerably larger, 5 to 10% expressed as $\sigma/\bar{X}$. This corresponds to a range of 10 to 20 kg/hr at an average solids feed rate of 195 kg/hr.

6. PERFORMANCE OF THE ASSOCIATED COAL FEED SYSTEM

When the primary coal injector is nearly empty, a new charge of coal and limestone must be transferred to it from the feed injector. Since coal feed rate to the combustor was very sensitive to changes in ΔP between the primary injector and combustor, ΔP had to be carefully controlled and monitored during transfers. ΔP is normally controlled by venting air from the primary injector at a constant rate and adding air through a control valve. However, coal entering the primary injector during transfers carries with it transport air, so that there was a tendency for overpressuring the injector. Therefore, in order to relieve some of this pressure, additional air was vented during transfers through a second valve. Considerable tuning of the system was necessary to make sure that the ΔP stayed within the desired range, and to avoid plugging of the valve by fine coal particulates in the vent stream.

7. ACKNOWLEDGEMENTS

The development of the temperature control system described in this report was done under EPA Contracts No. 68-02-0617 and 68-02-1312. The miniplant was designed under EPA Contract No. CPA 70-19 and constructed under Contract No. 68-02-0617.

FIGURE 1

PRESSURIZED FLUIDIZED BED COAL COMBUSTION SYSTEM

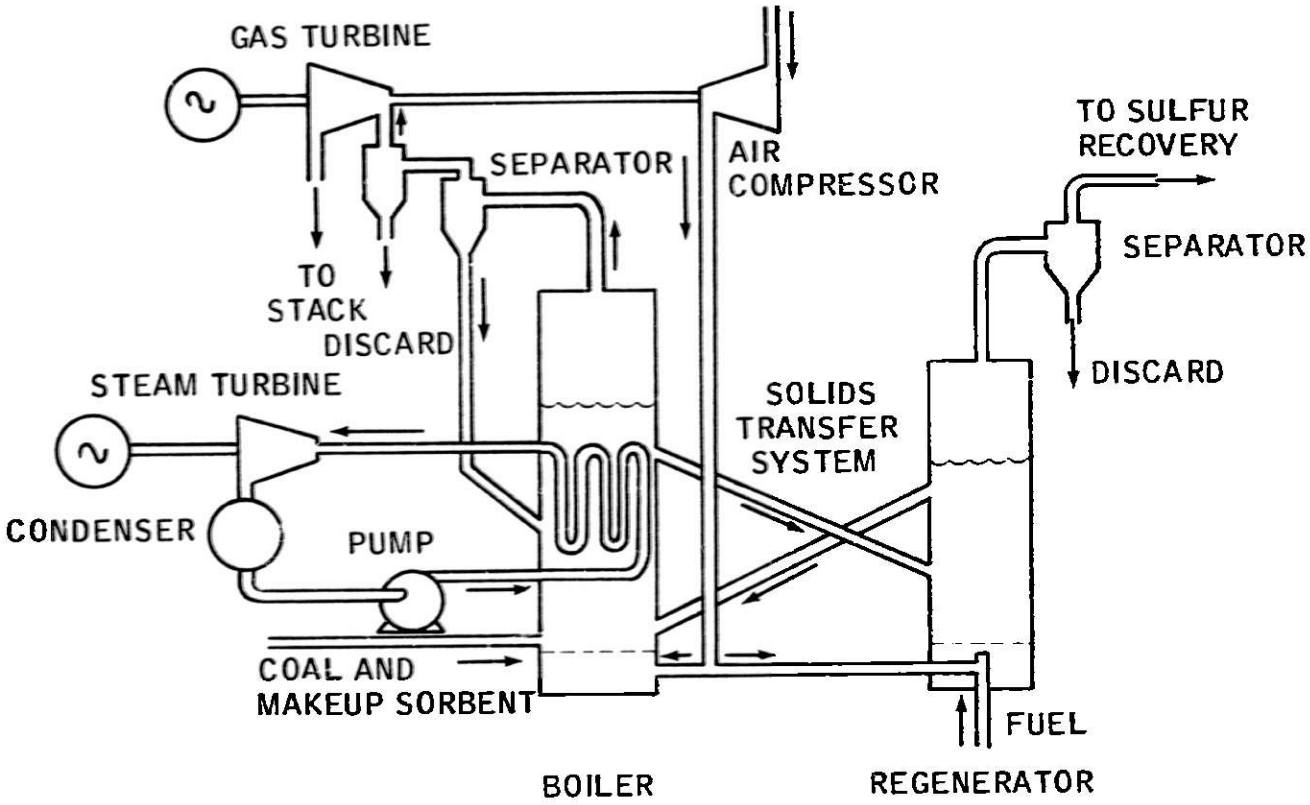


FIGURE 2

EXXON FLUIDIZED BED COMBUSTION MINIPLANT

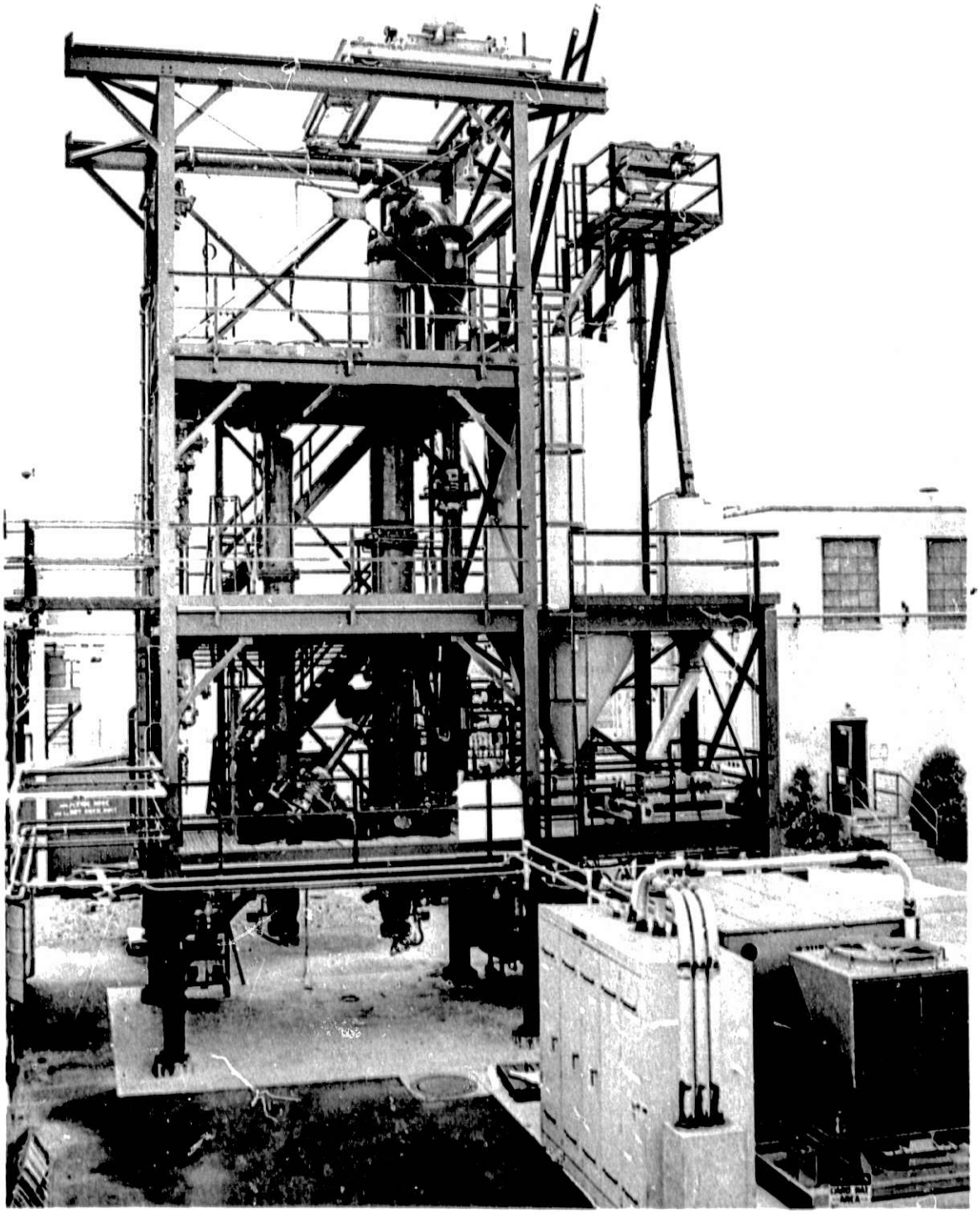


FIGURE 3

COAL AND LIMESTONE FEED SYSTEM

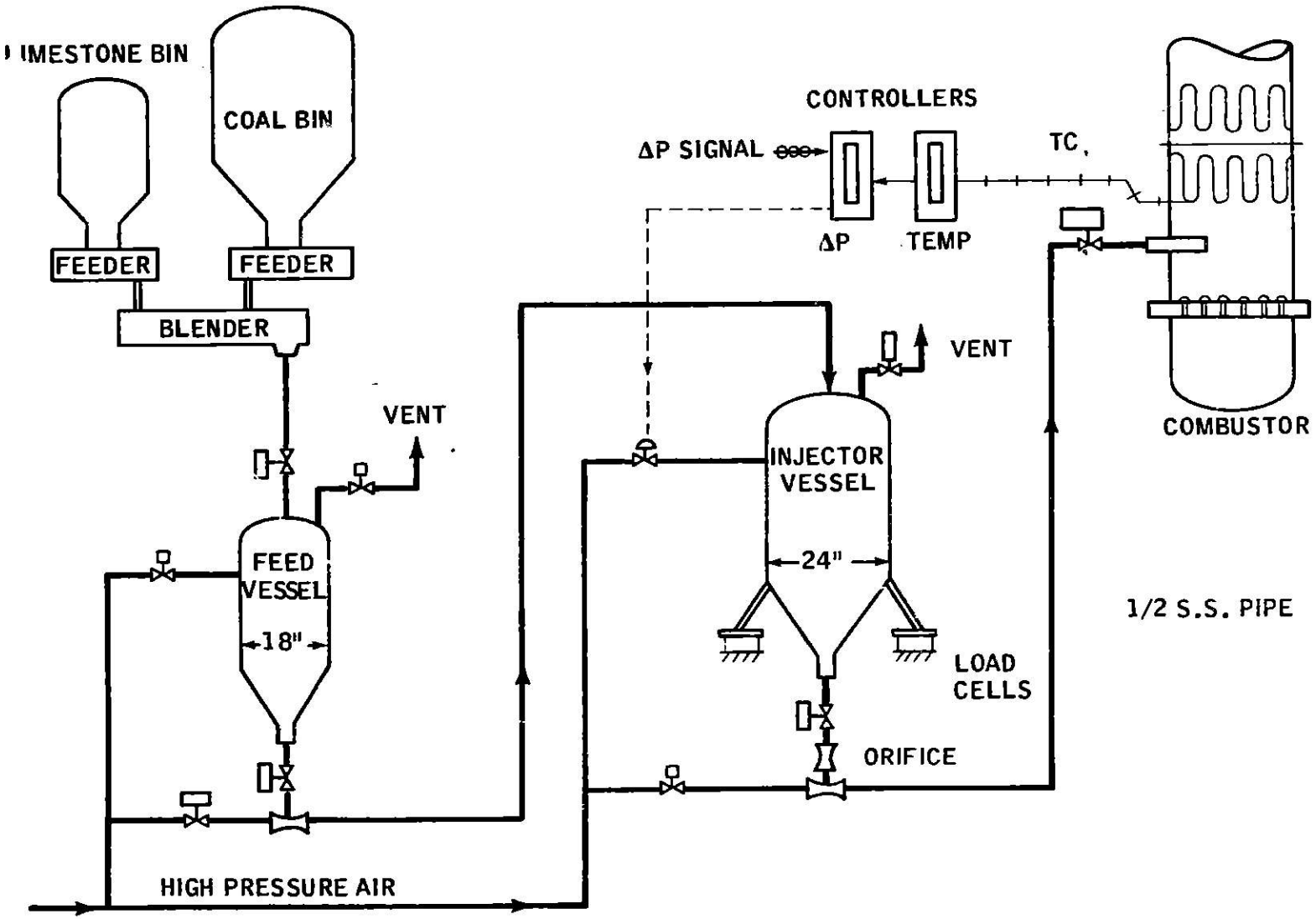


FIGURE 4
COMBUSTOR TEMPERATURE CONTROL SCHEMATIC

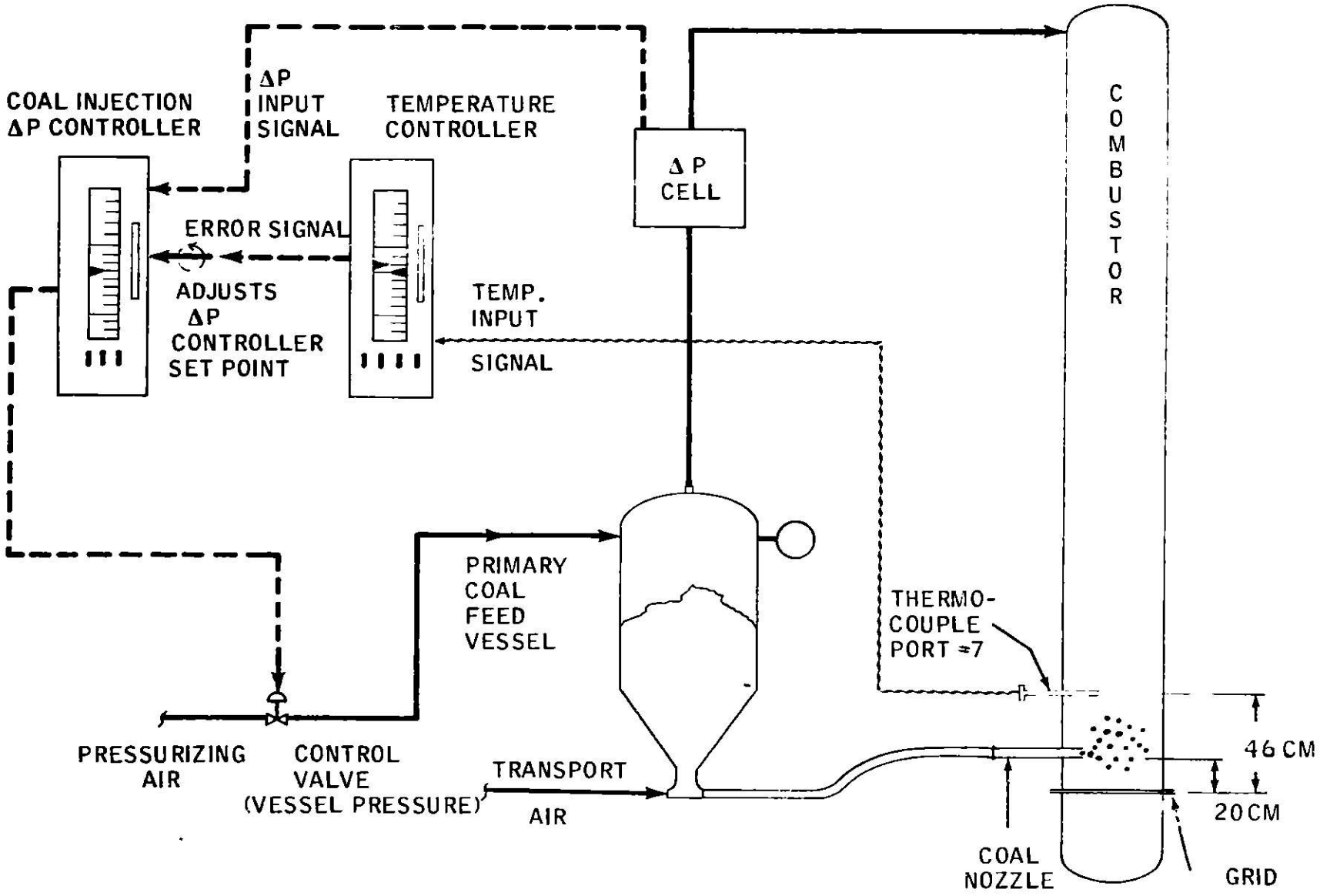
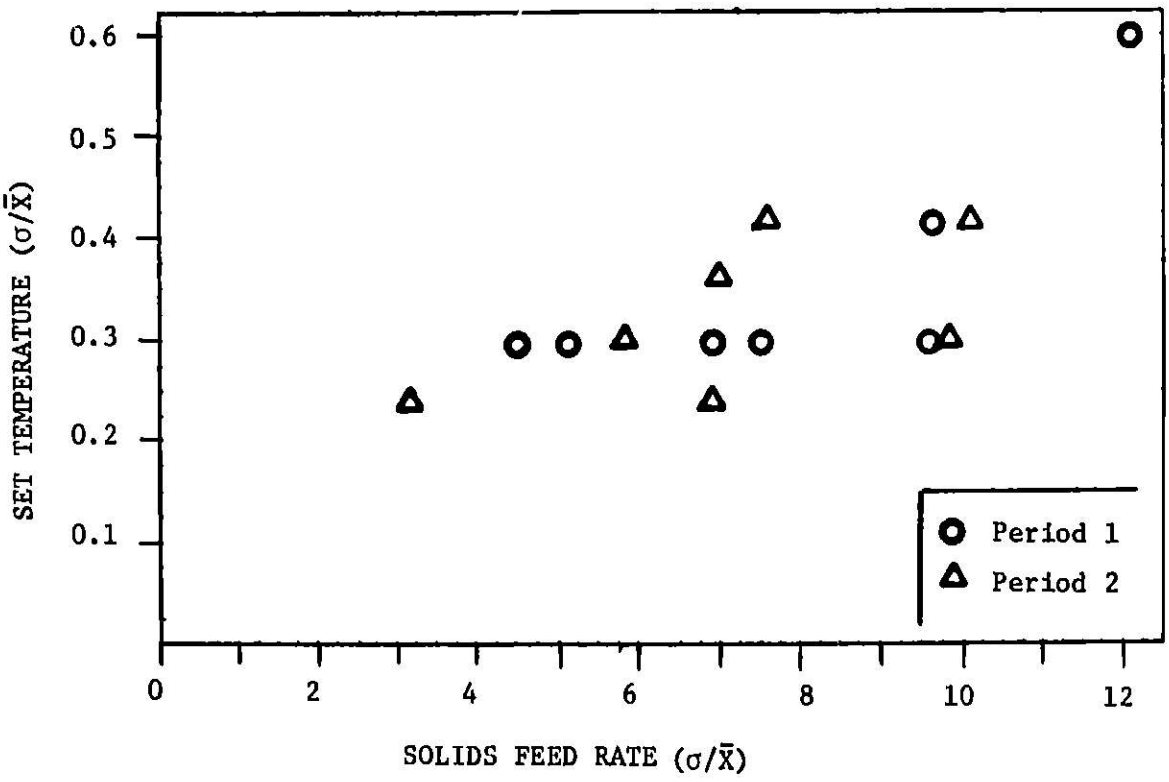


FIGURE 5

20 MINUTE STANDARD DEVIATIONS - Run No. 52



QUESTIONS AND ANSWERS

R. R. Bertrand

Exxon Research and Engineering Company

W. J. Haas, Ames Laboratory, ERDA

Q. What is the title and number of the EPA report you mentioned?

A. The EPA report that I mentioned is called "Studies of the Pressurized Fluidized Bed Coal Combustion Process," and has the number EPA-600/7-76-011, September, 1976.

Bela G. Lipták, Lipták Assoc.

Q. Do you differentiate the load cell signals by time to arrive at coal flow?

A. The data acquisition signal measures the total amount of solids in the feed hopper each minute based on the weight on the load cells. By differentiating the weight during our computer work-up of the data, we obtain the coal flow rate into the system.

R. W. Pfeiffer, Procon, Inc.

Q. What is the normal range of superficial gas velocities in the combustor?

A. Normally, we run between six and seven feet per second superficial velocity. We have run the system at superficial velocities between four and eleven feet per second.

Q. What is the normal range of operating pressures in the combustor?

A. That range is nine to ten atmospheres absolute.

Donald L. Bonk, Babcock and Wilcox Research

Q. When attempting electrical load following via. temperature control based on changes in coal feedrate, what are the values of excess oxygen in the flue gas?

A. Normally we have run at an excess air level between 20 and 60 percent. This value has been preset depending on the operating condition we were trying to achieve. We have not tried to follow load in the system, but we have observed that the excess oxygen will increase if we cut back on the coal feed rate.

J. F. Schooley, National Bureau of Standards

Q. What method of temperature measurement is used in the 30 foot high combustor.

A. We are using thermocouples inserted in a silicon carbide thermowell. In order to prevent the thermowell from occasionally being snapped off by the motion of the bed, a 1/4 inch diameter inconel tube which has been bored to 1/8 inch internal diameter is inserted into the well as a stiffener. A 1/8 inch diameter sheated thermocouple is inserted into the inconel tube.

J. P. Meyer, Oak Ridge National Laboratory

Q. Do temperature fluctuations increase as the temperature in the bed is decreased or are they fairly constant over the entire operating range?

A. We haven't really noticed a decrease in the absolute magnitude of the fluctuations as we dropped the bed temperature. The absolute value seems to remain about constant, somewhere on the order of six or seven degrees Farenheit.

M. R. Cines, Phillips Petroleum Company

Q. Is the feed cell aerated to allow flow of coal down through the bottom? How do you prevent bridging across the orifice?

A. We aerate through the cove in the primary feed injector, just above the orifice, in order to keep the solids moving somewhat to reduce the possibility of bridging.

R. M. Hurd, Materials Consulting Engineer

Q. Why is it necessary to very the temperature in the combustor to control steam rate? Can't you operate at constant temperature and control feed rates to get different desired heat rates?

A. Varying the temperature in the combustor is but one way to follow load. By passing air around the combustor so it goes directly to the turbine and dropping the bed level to decrease the steam make are other ways to follow load demands.

D. D. Bruns, University of Tennessee

Q. One function stated for the limestone is to serve as a heat transfer medium, how critical is this function? Will this cause stability problems as different S-composition coals are run through the combustor?

A. None that we have noticed.

Q. Has O_2 been used in place of the air? How does this effect the NO_x problem.

A. We have not run with enriched air or pure oxygen.

C. K. Sanathanan, University of Illinois

Q. What obstacles do you see in scaling up your system?

A. Demonstrating that heat exchanger and turbine materials will have economic lifetimes in the FBC environment is the main obstacle to scale-up.

G. N. Reddy, Argonne National Laboratory

Q. Could you describe the sequence of controlling (i.e., feed forward or otherwise) for load following capability within the range when the gas turbine is operating at capacity?

A. (No answer given.)

Q. What kind of gas cleaning system is used prior to the gas turbine and what is the gas turbine inlet temperature?

A. Two stages of inertial cyclones are current used on the miniplant. A granular bed filter will be investigated as a potential third stage of gas clean-up.

W. M. Miller, Stearns-Roger

Q. What is the method of measuring the solid feed to the blender?

A. By pre-calibrating the coal delivered for a given feed screw setting.

A. C. Tulumello, Delta Scientific

Q. I would look for valve failures to be a problem on your delivery system. What is your experience?

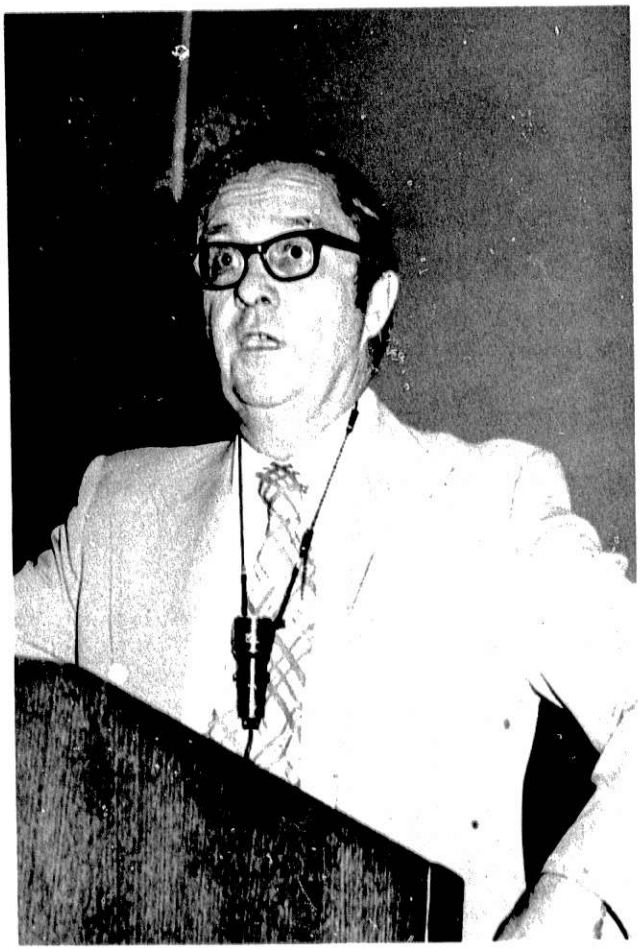
A. We have had valve failures which resulted from coal dust blocking the orifices or eroding the valve seats.

E. S. Giordano, Badger Plants, Inc.

Q. Do you see the need for a better method of measurement of coal and limestone feed to the combustor for commercial-sized plants and, if so, what methods will you consider? (i.e., Will weight cells be applicable to commercial sized plants?)

A. We see the need for a better measurement system, but have not yet evaluated alternate methods.

INSTRUMENTATION AND DATA ACQUISITION TECHNIQUES IN THE HYGAS PILOT PLANT



W. G. Bair
HYGAS PILOT PLANT
Institute of Gas Technology
Chicago, Illinois

INSTRUMENTATION AND DATA ACQUISITION TECHNIQUES IN THE HYGAS PILOT PLANT

by
W. G. Bair
Institute of Gas Technology

1. INTRODUCTION

The HYGAS® pilot plant perhaps has the longest history of extended operation of any of the second generation coal gasification pilot plants sponsored by the ERDA/A.G.A. joint program. The plant, located in Chicago, Illinois, has processed almost 10,000 tons of coal including all major U. S. coals from lignite and subbituminous through Illinois basin bituminous coals.

Today, I would like to briefly review the process, describing principal features, and to discuss the instrumentation and data acquisition techniques routinely used and describe how they function in our program. I would like to describe some of the applications of new instruments, and to summarize development needs.

2. HYGAS PROCESS DESCRIPTION

Figure 1 shows a flow sheet for the HYGAS process. This process utilizes a fluidized-bed reactor, operating at pressures of 1000 to 1500 psig and temperatures in the range of 1300° to 1800°F, to convert the major part of the carbon in coal to gases. Between 5 and 10 weight percent of the coal feed is produced as a light aromatic oil, principally toluene. The HYGAS process maximizes methane production in the reactor by using direct hydrogenation of coal. About two-thirds of the methane in the final product gas is produced here, and only one-third in a clean-up methanation process.

The essential features of the HYGAS pilot plant are:

1. A coal preparation area where as-received coal can be ground to 10 to 100 U.S. sieve size and dried to remove surface moisture.
2. A pretreater which is a low-pressure, air-oxidation system utilizing fluidized-bed contacting and which is used on agglomerating bituminous coal to prepare a non-agglomerating material for feed to the reactor.

3. Slurry mixing and pumping. The HYGAS process utilizes a wet-feed coal-oil slurry which is pumped to high pressure and introduced to the reactor system. The light oil that is produced in the reactor, as a part of the process product stream, is recycled and used as the slurry vehicle.

4. The reactor is a series of fluidized beds and starts with a slurry-drying zone in the top. The dry solids are then transferred through dense-phase transfer pipes to two hydrogasification stages and finally to the steam-oxygen zone where the hydrogen needed for direct hydrogenation of the coal is produced by the steam-oxygen gasification of the residual char.

5. The gas quench system, consisting of two direct-water-contact towers in series, which cools the product gases from about 650^{o} down to 100^{o}F. The condensibles, unreacted steam, and the slurry light oil are condensed and taken to a phase separator where the light oil and water are allowed to separate. The light oil is drawn off and the water is recirculated to the quench section. The net water and net product oil are recovered and measured.

6. Gas purification. The pilot plant utilizes a recirculating diglycolamine solution to remove acid-gases (principally carbon dioxide, hydrogen sulfide, and smaller amounts of other organic sulfur compounds) by absorption in a packed column. The rich amine solution is regenerated in a low-pressure steam stripper and pumped back to the absorber vessel. This gas purification system, probably not the one that will be used in commercial HYGAS plants, is used in the pilot plant because of convenience.

7. Clean-up methanation. Following gas purification, the remaining one-third of the methane in the final product gas is produced by catalytic methanation of the hydrogen and carbon monoxide mixtures left in the purified product gases. This is done over a fixed-bed nickel catalyst which requires extremely good sulfur removal to maintain high catalyst activity. Therefore, we utilize a zinc oxide sulfur guard chamber

upstream of the catalyst reactor to remove traces of sulfur compounds that have escaped removal in the gas purification system.

These are the essential process sections of the HYGAS pilot plant.

3. INSTRUMENTATION

Essentially all the HYGAS instrumentation is conventional, off-the-shelf hardware specially applied to work properly in the required environment. The pretreater and the main HYGAS reactor are fluidized-bed reaction systems for gas-solids contacting. The most important criteria for proper control of fluidized-bed reactor systems are accurately knowing the bed density and the total bed volume or bed height. Conventional differential pressure techniques are used for both measurements. This is much like using a simple manometer to measure the difference in pressure between the top and bottom of a liquid-filled tank to determine the total inventory or total volume in the tank. In the case of low-pressure liquid systems, the density or specific gravity is usually a known constant for a given system. In our fluidized-bed application, this is not so. The density of the bed varies as gas throughput and bed expansion vary for different processing conditions. We therefore measure the bed density using the pressure difference between two fixed points of known elevation. Overall bed height is then measured using the total pressure drop over the entire fluidized-bed system and the bed density which was determined by the fixed-distance taps.

These techniques are applied to the pretreater reactor, which operates at atmospheric pressure and about 700° to 800°F. This instrumentation is conventional and, because gases are used, the hydrostatic head (the inaccuracy caused by differences in elevation between the two taps) can be neglected. However, when this same differential pressure measurement technique is applied to the HYGAS reactor, the inaccuracy caused by neglecting the hydrostatic head between two taps at 1000 to 1500 psig can be considerable. For example, at 1000 psig the density of the gas in the transmission legs of the ΔP instrument is approximately 5 pounds per cubic foot. At this density, a foot of vertical height difference between pressure sensing taps is equivalent to one inch of water pressure differential. This difference in hydrostatic head must be taken into consideration for gas-phase measurements at high pressure.

The HYGAS reactor, shown in Figure 2, is 132 feet high and several areas require very large vertical distances between ΔP tap locations. To normalize all readings in our plant, the hydrostatic head differential is calculated based on actual height and a zero supression kit is used to bias the individual ΔP transmitters with the correct hydrostatic head difference. This way, the the true differential can be measured within the reactor.

The reactor is the main area of experimental study in our process and development efforts and our instrumentation have been concentrated there. We measure bed levels and bed heights in each zone of the reactor. We measure standpipe densities and overall pressure drops for all solids transfer lines and we measure the differential pressure across all of the fluidized-bed gas distribution decks.

All systems using pressure sensing taps, where solids and/or condensible gases such as steam could be present, require purging the pressure tap legs with clean, dry, inert gas. This prevents solids or condensible liquids from accumulating in the sensing lines and either plugging the taps or causing instrument error. In the HYGAS pilot plant, we use dry, high-pressure nitrogen gas to purge taps on all ΔP transmitters and to keep the lines clear. These purges must be carefully regulated and frequently checked. Too low a flow will permit dust and condensible gases to accumulate in the pressure taps, while too large a flow will create a higher ΔP and bias the readings. The HYGAS reactor now has 34 individual differential pressure measurement instruments and requires 54 separate high-pressure nitrogen purge meters to control purge gas flows to these instruments. Some of the ΔP instruments share a common line and these require only one purge for two instrument taps. Also, some nitrogen purges are used for aeration of solids transfer lines.

Solids feed rates and total solids weights into both the pretreater reactor and the HYGAS reactor are measured by continuous weigh belt systems that are calibrated before and after each test to detect any drifting.

All liquid flows and gas flows are measured by conventional sharp-edge orifices installed according to recognized standards. Only the inlet coal oil feed slurries and the ash discharge slurry are excluded. The conventional sharp-edged orifices would erode rapidly with slurry mixtures, so we have

successfully used venturi-type flow meters for these streams. The venturi-type meter provides a streamlined flow pattern and has successfully eliminated erosion and consequent loss of accuracy in these meters over long time periods. With venturi-type flow meters, a clean liquid must be provided to flush the pressure sensing lines just as gas-phase differential pressure instrumentation requires a clean gas to flush these lines. We use a special, filtered, recycle-oil stream to flush the lines for the venturi meters; it prevents plugging and loss of sensitivity in measurement.

A magnetic flow meter is used on the low-pressure ash-water slurry streams. However, the magnetic flow meter cannot be applied to the oil slurry used in our feed streams.

Both the venturi meters and the magnetic flow meters need accurate flowing-density information for calculating mass flow rates. In the HYGAS plant, we use a nuclear densitometer to measure the flowing density of the oil-coal slurry streams for the plant input and the ash-water slurry streams for the solids exit stream. The instrument utilizes a cesium 137, 100 millicurie source of gamma radiation and is attached directly to the slurry pipeline. The absorption of gamma radiation depends on the amount and density of the process material in the pipeline, and variations in flowing densities can be detected from the differences in gamma radiation absorbed by the flowing medium. These instruments give reliable and repeatable results when a continuous liquid phase is present in the pipeline. Our sporadic readings have been traced to the presence of trapped gas bubbles resulting in two-phase flow in the pipe.

Temperature measurement in the HYGAS pilot plant is accomplished by conventional thermometry. We use chromel-alumel (type K) thermocouple junctions for temperatures between 1000^{o} and 2000^{o}F and iron-constantan (type J) thermocouple junctions for temperatures below 1000^{o}F. This has given reliable service. The only problems are finding a suitable sealing mechanism to introduce the thermocouples to the high-pressure, high-temperature environment. Conax sealing glands have been successfully used on the HYGAS reactor area for this purpose.

For liquid level detection and control, we have used both differential pressure equipment and conventional float-type, cage-mounted equipment. Both have been satisfactory. However, both instrument types require purging

the attachments to the process vessel to prevent coal solids from interfering with their operation, as do the ΔP instruments used in the reactor gas phase and slurry venturi metering applications mentioned before. The solids are purged from the sensing taps and kept out of the float chambers or the chamber around the differential pressure cell, by using a clear water or clear oil purge stream.

Flow control of erosive slurry streams was a particular problem in initial HYGAS pilot plant operations, especially where the pressure was reduced from the operating level of 1000 psi to atmospheric. The exit slurry streams were originally equipped with globe pattern flow valves. These gave a very short service life due to the very high pressure drop and the erosive nature of the material being handled. We have since successfully applied a rotary choke, single or multiple orifice valve with a diaphragm actuator. This was originally developed for throttling crude oil and raw natural gas at producing wells. The throttling mechanism consists of two tungsten-carbide circular disks with diamond-lapped mating services and a single or multiple orifice. With one disk fixed in the valve body, the other may be rotated 90^{o} to open or block the flow area. When throttling and closing, this mechanism provides a shearing force to cut any trapped solids particles in the slurry. Less force is required, minimizing the seating surface damage common in the globe valve. The tungsten-carbide disk reduces erosion of the orifices. Several modifications of the original equipment have been required to apply this device to flow control of erosive slurries. We now get a very satisfactory life, and the problem of pressure letdown of erosive slurries has been solved in our HYGAS pilot plant operations.

Gas compositions in the pilot plant are monitored by on-line gas chromatographs. Two chromatographs now operate; one monitors hydrocarbons and the other monitors trace sulfur compounds in the purified gas stream before it enters the methanation system. An in-plant computer system controls the operation of the chromatographs, converts the readings to mole percents, and gives us a teletype printout of the composition of the major process streams in the gas phase for monitoring plant operations.

4. DATA ACQUISITION

We also monitor 148 data points of temperature, pressure, flow, and differential pressure throughout the process system using a Scanivalve system for converting the pneumatic signals to EMF. These data points are recorded on magtape, and the on-line computer then uses the information to compute the average material balance of the plant on an instantaneous or a 2 hour average basis. The individual data points are monitored at a rate of 150 points per minute, so that all data points in the plant are recorded approximately once a minute.

The computer program is also used to calculate bed densities and bed heights in the various parts of the reactor system where this information is needed. This allows us to check closely on the conditions during the run, and it is invaluable in determining when operational changes are needed to achieve the goals of test operations.

Basic information on the composition of solids streams in the HYGAS plant is still attained by conventional methods. This requires a relatively long time lag before information on the composition of the various solids streams can be determined. For the on-line computer material balance calculations, we estimate the solids input streams composition based on past experience. However, we would like to have a faster method to determine on-line analyses for the solids in the various stages of the process.

5. EXPERIMENTAL INSTRUMENTATION

In several areas of the HYGAS pilot plant operations, we are not satisfied with the information that is obtainable from conventional instrumentation systems. One important area for safety assurance would be to detect any high-temperature area of the metal wall of the gasifier reactor or associated piping that would indicate deterioration of the refractory lining. Several approaches to the problem have been suggested, including multiple thermocouple blankets over the area in question or temperature sensitive paints. These methods, while partially effective, do not allow early detection or are subject to other problems such as weather interferences.

One approach is to use a continuous infrared monitor to read out temperatures of the area in question. Infrared detectors are widely used for temperature sensing, but a system specifically designed for the conditions

in our experimental program could not be readily purchased. IGT adapted a commercially available instrument to our specific requirements, to determine how applicable this type of instrumentation is. Specifically, we wanted to scan a 2-foot section of the metal wall of our start-up burner piping, which is used for initiating plant operation. A model 6000 IRCON unit, with a temperature range of 150^{o} to 400^{o}F, a one second response time, and a wave length of 2 to 2-1/2 microns, has been thus adapted. The unit was selected for its suitability for subincandescent temperature measurements and for a feature that minimizes the atmospheric absorption of infrared energy by water vapor (humidity) and carbon dioxide at the operating wave lengths. The target size on the 3-inch pipe is 2.5 inches. We had to fabricate a special bracket to make the beginning point of the scan as close as possible to the 24-inch pipe section in question. We used a 24-inch pneumatic ram to traverse the section of pipe with a stroke speed of approximately 2 minutes to traverse up and back.

The unit has been in service for over a year and, so far, has been entirely satisfactory. To date, the only unsolved problem has been a high-temperature reading when the early morning and late evening sun rays strike the pipe surface and the scanner sees a bright spot and reads it as a higher temperature. We plan to modify this system to adequately shield the area from direct sun radiation to solve this problem.

Working with the manufacturer of a magnetic resonance flow meter that could possibly meter the flow of the oil coal slurry on our input stream, we have developed a high-pressure housing for their conventional apparatus which could only operate at pressures of about 50 psig. We are now awaiting delivery of the equipment from the manufacturer, and will hopefully put this equipment in service soon to see if this system can be applied at the high pressures needed for introducing the oil-coal slurry into the HYGAS reactor.

We are also working with Argonne National Laboratories to develop acoustical meters for slurry flow rate measurements. We are working to develop a hot gas sampling system for interstage sampling between the various reaction zones of the HYGAS reactor. This would allow us to monitor gas compositions between zones and estimate conversion levels for the various stages of the HYGAS process. This is an extremely difficult task,

involving sampling gas streams containing condensibles and particulate matter at temperatures of up to 1850°F and pressures of 1000 psig and higher. We have made some progress, but have not yet developed a system that will give us reliable, continuous service. We intend to continue development work in this area.

6. SUMMARY

Process control and meaningful, accurate process data have been achieved in the operation of the HYGAS pilot plant. But, as process operators, we are never satisfied. The ideal instrument, from the process operator's point of view, is one that would require no sensing elements to interfere with the process stream, would have absolutely no drift and never go out of calibration, and would be able to give us instantaneous on-line information. The instrument would not be affected by high or low temperatures, by high or low humidity, by corrosive liquids, or particulate matter. We are always looking for the development of the ultimate instrument. Although existing technology is satisfactory in many ways, it is through the use of instrumentation specialists and meetings such as this that ideas can be developed and implemented which will lead to improved instrumentation for the emerging coal conversion technologies.

7. ACKNOWLEDGMENT

The work described in this paper was performed under a program jointly sponsored by the United States Energy Research and Development Administration and the American Gas Association.

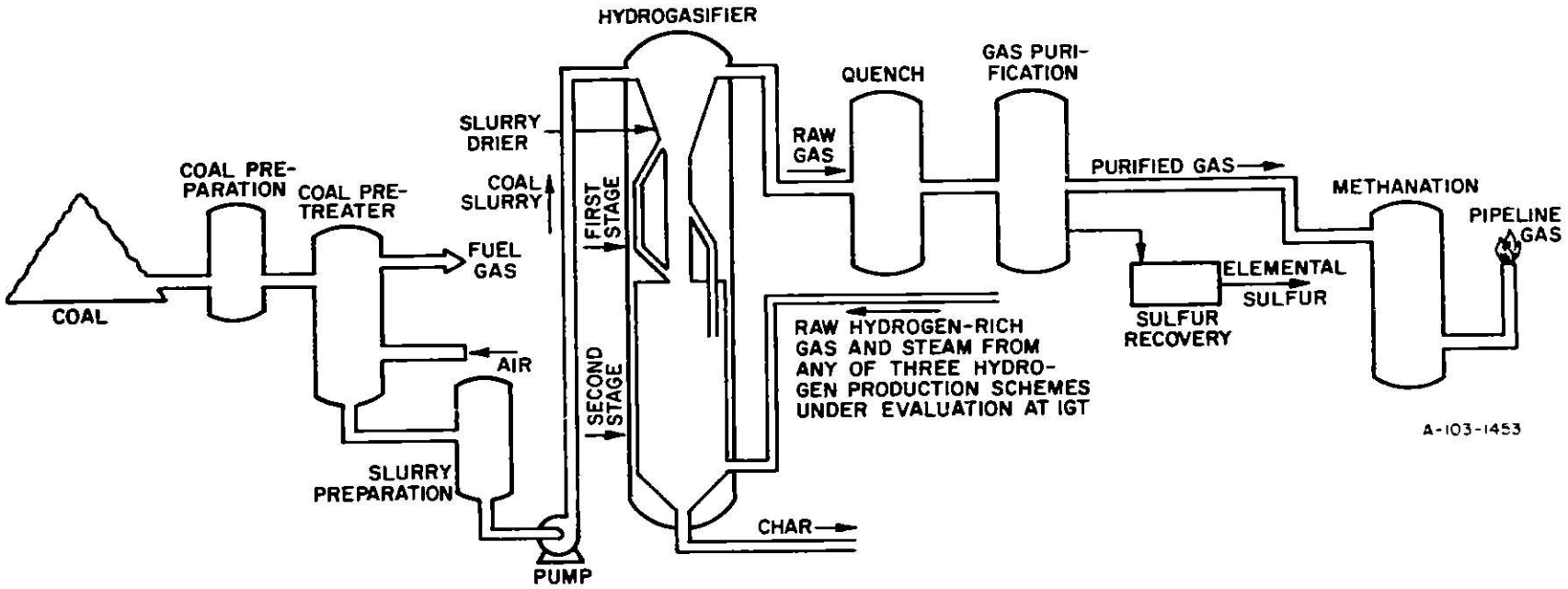


Figure 1. HYGAS PROCESS FLOW SHEET

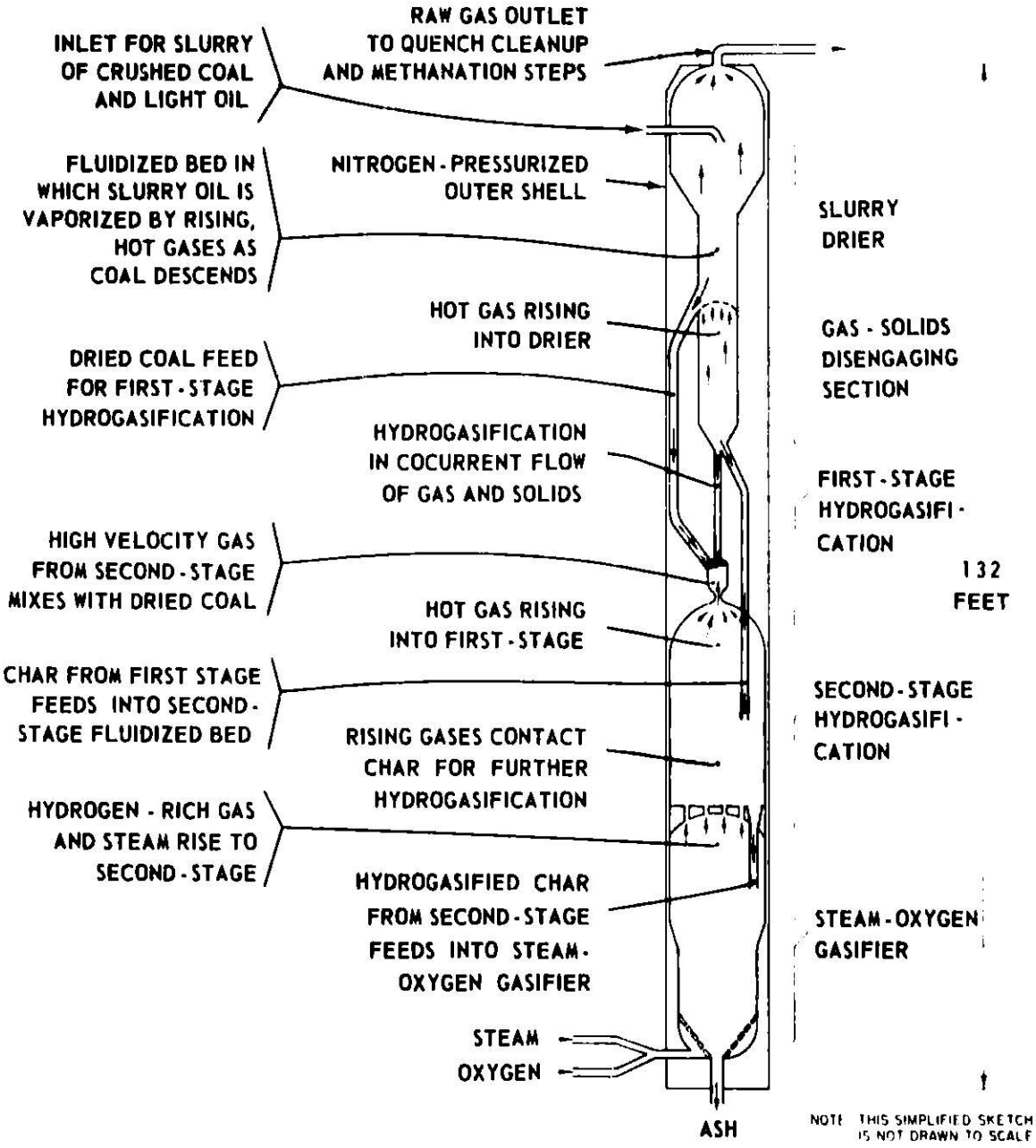


Figure 2. DETAILS OF THE HYGAS PILOT PLANT GASIFICATION REACTOR

QUESTIONS AND ANSWERS

W. G. Bair

Institute of Gas Technology

B. G. Liptak, Liptak Associates

Q. In addition to Scani Valves do you also use other types of valves?

A. No we do not. We have used the Scani valve brandname hardware exclusively and I don't know anything about any other type of equipment.

Q. Is the magnetic resonance flow meter by Badger?

A. Yes.

N. M. O'Fallon, Argonne National Laboratory

Q. How well did the electromagnetic flowmeter work on the ash slurry stream?

A. Fairly well. It is not completely ideal and I don't think that we implied that they are completely ideal systems, but they did give us some response which we feel could be developed into a useful instrument.

Q. What time lag exists between gas stream sampling and completion of analysis by the chromatograph?

A. Our sample lines obviously are several hundred feet in length in certain places. The time lag involved in getting the sample to the instrument is about two minutes. The sample cycle for the instrument is about eight minutes. So that is a total time lag of about ten minutes, however, that chromatograph also looks at three consecutive hydro-carbon streams. The raw gas, the purified product gas, and the gas after methanation, so that I have about a 30 minute cycle before I repeat my analysis on the hydrocarbon stream on any one location. The sulfur chromatograph only looks at the purified product gas after sulfur removal so its cycle time is on the order of ten minutes.

R. W. Doering, Argonne National Laboratory

Q. You mentioned your gas chromatograph composition analysis system having computer printout and control. What is the time delay between system change and printout in your present system. What is the needed time delay maximum in your plant?

A. There is virtually no time delay in the computation of the analysis, so the time delays mentioned above would apply. I'll find that out for you. What is the needed time delay in your plant? We normally try to run for periods of 24 or 48 hours at a given steady state condition. What I'm

mainly interested in in time, is how rapidly we can come to a steady state condition and what is happening when we are changing conditions. The time delay that we are currently experiencing is entirely satisfactory for our operations although if we could make it faster I would like to.

E. S. Giordano, Badger Plants Inc.

Q. Who is the vendor of the magnetic flowmeter mentioned? Please expand on IGT's evaluation of the Willis choke valves, i.e. is it applicable to commercial sized plants?

A. I would think it would be completely applicable. We are using the smallest size they make with a 1/4 in. orifice, which we need for our flow rates and our pressure drops. The Willis Oil Tool Company of Long Beach, CA, is the supplier and I definitely remember that name because we called frequently about three years ago. I'm not trying to plug anybody's products, believe me, Willis normally makes these devices for crude petroleum well heads, christmas trees, and raw natural gas well flow control, and they make them in very large sizes.

M. P. Cines, Phillips Petroleum Company

Q. With 55 N_2 purge points on the reactor, what is the N_2 concentration in the final methane?

A. In our final plant operations, the percent nitrogen in the final product gas is a function, of course, of throughput. The purge rates are fixed and they have a constant volume of nitrogen flowing per hour. The more coal we feed, and the more gas we make, then the lower the concentration in the final product gas. Normally that concentration runs about eight or nine percent.

R. Chandrasekhar, Foster-Miller Associates

Q. Re: Venturi flowmeters for slurry flow measurement. Are these lined for abrasion resistance? If so with what? Life expectancy.

A. The slurry flowmeters are made out of type 316 stainless steel machined to our dimensions, there is no secret to the dimensions or anything, I think we used a formula out of Perry's (which is a chemical engineering handbook for you people who are in the instrument society). We have had these devices installed for at least two years, and we have had a minimum of errosion.

John J. Eichholz, Argonne National Laboratory

Q. Manufacturer of IR temperature scanner? Is it a single detector instrument?

A. The manufacturer of the IR temperature scanner is IRCON Model 6000, working on a wave length of 2 to 2-1/2 microns, I think.

H. Kaplan, Barnes Engineering

Q. Suggestion: if what you see in the morning is reflected sunlight, spectral filtering would probably be a better fix than enclosing your IR sensor.

A. Thank you very much. I'm not sure what you're talking about, but I'd like to learn.

G. N. Stenbakken, National Bureau of Standards

Q. What type of dP cells are you using: e.g., strain gauges, etc.?

A. No, they are a diaphram type of dP cell, they are not strain gauges.

LUNCHEON

Master of Cermonies

J. L. Powell, Jr., Chief, Equipment Branch
ERDA - Fossil Energy
Division of Major Facilities Project Management
Washington, D. C.

OVERVIEW OF ERDA - FOSSIL ENERGY DEMONSTRATION PLANT PROGRAM

G. A. Rial, Director
ERDA - Fossil Energy
Division of Major Facilities Project Management
Washington, D. C.

OVERVIEW OF ERDA-FOSSIL ENERGY DEMONSTRATION PLANT PROGRAM
INSTRUMENTATION AND CONTROL FOR FOSSIL DEMONSTRATION PLANTS
JULY 13-15, 1977

G. A. RIAL
DIVISION OF MAJOR FACILITY PROJECT MANAGEMENT
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

I once heard someone say that one reason we are a great Nation is that despite our best efforts, we have been unable to exhaust our natural resources. While we are faced with diminishing supplies of oil and gas, we as a Nation, are still blessed with resources of coal and shale. To best use these resources, ERDA is sponsoring a joint industry/government program to build and operate plants to demonstrate promising coal and oil shale processes at near commercial scale.

For those first plants to come on line we will need your skills and creative energies. I am talking about the need for greatly improved controls and instrumentation which meet the needs of the new industry. Without them, a plant would be merely an inanimate collection of vessels, materials handling equipment, pipes and compressors, but controls and instrumentation can hold them together and bring the end plant into being. And they can enhance the commercial appeal of a process by improving the economics -- using fewer people and resources and producing a better final product. We are concerned about control requirements, i.e., mass flow measurements in various phases -- solids or gas handling or mixed phase handling including coal or char at critical temperatures and pressures under hostile conditions, especially for on-line measurement. These measurements are needed for mass balance and heat balance on the technical side; and safety, reliability and problem diagnosis on the operating side.

Moreover, improved controls and instrumentation may help overcome environmental barriers to such new technology. I can't emphasize the environmental equation too strongly, since the environmental rules of the game are getting tougher all the time. While many of us from the process industry feel such standards are too strict or perhaps unwarranted, nevertheless we must deal with them. We must identify and record the major emissions surrounding new technologies so that the necessary work in emissions characterization, controls development and effects analysis can go on parallel to other R,D&D. We

must do that because technologies which cannot be made operable in an environmental sense won't be commercialized. Moreover, we can only resolve the debate concerning whether current environmental standards are too stringent, if we have an accurate way to define and record emissions. This is a fertile field for instrument development.

A second concern relates to the fact that coal and shale utilization programs now combine problems of both the mining and process industries. With the great expansion of the mining industry associated with coal and shale utilization, there will be greatly increased handling of materials in the processing. Here again, identification and control of environmentally hazardous conditions become very important.

Now, before I fill you in on the Fossil Energy Demonstration Plant activities, which are my responsibility, I would like to give you some overview. As you know, the Fossil Energy Program is critical to providing alternatives to domestic supplies of oil and natural gas. Our program can help meet the Nation's near term needs -- that is, it can produce significant quantities of energy-bearing products before year 2000.

We concentrate on alternatives to petroleum and natural gas. Our resources are coal and oil shale which cannot be utilized economically or in an environmentally acceptable manner in the present price structure. These resources are abundant. In total, they can supply all of the Nation's additional energy needs for over a century -- more than enough time, one would hope, to develop technologies that economically exploit the "inexhaustible" resources of the sun.

We need that fossil "bridge" to the next century because the decline in worldwide oil and gas production coupled with a 2-3 percent annual demand growth, spell out the possibility of a physical inability to meet fuel requirements at any price. That is the real energy problem confronting us. In solving this problem, we must realize that conservation, though important, is not the whole answer. We also need new supplies. We must utilize our coal and shale reserves promptly, economically and in an environmentally acceptable way.

That means we are developing our domestic energy alternatives and adapting to a new resource base more quickly than ever before. In the past, it took 60 years to move from reliance on one major energy resource to reliance on another. But because oil and gas production has peaked, we don't have 60 years to make the transition -- only about 15 years remain for us to accomplish that monumental task. The Fossil Energy Demonstration Plant Program will be one of many avenues to achieving that.

That program has several goals. The first is to demonstrate at near commercial scale promising second generation coal and shale processes developed by both industry and government. At this time, no second generation processes have been built or operating, although there are first generation processes in commercial operation (but none of any significant size in the U.S.). I am referring to the conventional Lurgi, Koppers-Tozek and Winkler gasification processes and the Fischer-Tropsch process.

How big should a second generation demonstration process be? We think the right size would be one module, whereas a commercial plant might have three or four.

Alternatively, the demonstration plant size for a single train commercial unit should have a scaleup factor of no more than three or four to one. A commercial plant could be 20,000 t/d of coal. Accordingly, demonstration plants will probably range from 2,000 to 7,000 t/d. The cost of these plants will be in the order of $200-500 million each. These projects should be designed in a way that will permit expansion for a commercial operation if the demonstration proves successful. In all cases, the instrumentation for those projects should be commercial.

For the process under consideration, we expect that the technical problems identified in the pilot plant stage will have already been resolved. Subsequently, design and economic evaluations will have been carried out to establish a commercial project cost and the economic value of the process. It will take a significant amount of money to arrive at this point; but without such expenditure, the process is not ready to demonstrate.

Our second objective is to encourage industry participation. ERDA will do that by reducing the risk of the development through cost-sharing. Cost-sharing is desirable because it insures that projects have merit by private standards, thus encouraging high caliber, well thoughtout projects. Moreover, it insures that industry will make a later commitment of other resources to protect its investment.

In talking about the status of the Demonstration Plant Program, I am assuming that all of you know something about the processes selected and many of the technical features of the program. From my own background, I know that instrument designers and engineers must know as much about the process as the process design engineers. Now let us look at specific programs and their status.

High Btu Pipeline Gas

ERDA has completed negotiations with Conoco Coal Development Corporation for the conceptual design of a $370 million demonstration plant using the slagging Lurgi process, and with the Illinois Coal Gasification Group for the conceptual design of a $334 million demonstration plant using the COED/COGAS process to produce pipeline quality gas and low-sulfur synthetic crude from coal.

Industrial Fuel Gas

Negotiations with Memphis Light, Gas and Water Division of the City of Memphis and with W.R. Grace/Ebasco Services are almost completed. As you know, Memphis plans to use the U-Gas process to make medium btu gas to distribute in a city-sponsored gas system. Grace will use the Texaco gasification process to make syngas, which will be used in ammonia manufacture.

Small Industrial Fuel Gas

ERDA hopes to complete its negotiations with both Erie Mining and New Jersey Zinc by the middle of August. Erie Mining plans to utilize the low btu gas for taconite processing and New Jersey Zinc will utilize the low btu gas for indirect process heating for the smelting operation.

Utility Fuel Gas

We have not yet picked a contractor.

Clearly, the gasification portion of the Demonstration Plant Program is well developed. The contract negotiations have not been carried out as quickly as we originally planned, because there have been significant business problems to resolve. But by the end of this summer, we hope that conceptual design activities for all of these programs will be underway.

In looking to the future, the 1978 budget requests have listed two demonstration plants; one for an Atmospheric Fluidized Bed Direct Combustion (AFB) project and the second for a Solvent Refined Coal (SRC) project. Planning is presently underway to help initiate both the Atmospheric Fluidized Bed Direct Combustion project and the SRC project. The AFB project was authorized in FY 1976 and we expect appropriation in FY 1978. The SRC project has no budget status at the present time. However, it was included in the President's energy message.

The Atmospheric Fluidized Bed Direct Combustion process is the combustion of coal in a fluidized bed containing dolomite or limestone. Boiler tubes are in direct contact with the fluidized bed. There is every indication that the Atmospheric Fluidized Bed Direct Combustion technique is a standoff with conventional boilers and stack gas scrubbing. With the difficulties which have been experienced with scrubbing, the Atmospheric Fluidized Bed System may be more attractive from an operational and flexibility standpoint. The electric utility industry is extremely interested in this development because it has an urgent need to make investment in a new capacity in the mid-1980's. There is a 30 megawatt thermal fluidized bed boiler pilot plant installation starting up at Rivesville, West Virginia. Assuming successful operation of this unit, it is planned to move ahead quickly to design and construct a demonstration plant which will be acceptable to the utility industry.

The SRC project is less well defined. Congress is asking ERDA to evaluate the SRC I and SRC II processes and their relative markets before proceeding with a project. The electric utility industry is also interested in the SRC product because this process eliminates a large amount of the ash and sulfur

from the coal feed. About 240 tons per day of SRC coal were burned over the last several weeks at Plant Mitchell, Putney, Georgia. Sulfur and nitrogen oxide emissions were well below EPA state standards Particulate emission data are still being evaluated.

Shale oil products are atractive because they have the potential of costing $6/barrel less than products from coal conversion and utilization. For this reason, ERDA plans to address the shale oil program very vigorously in the coming year. On an optimum basis, products from shale oil processing won't be available until 1981.

Besides my own program, ERDA Fossil Energy has a companion program -- a commercial demonstration program which will utilize first generation technologies. After the defeat of the Synfuels Bill, this program was transferred to the ERDA Fossil Energy Assistant Administrator.

At this time, we are working with Congress and with OMB to develop this program. Why do we need it? We need it because an immediate commercial demonstration program would reduce a number of uncertainties related to economic and environmental feasibility, socioeconomic impacts, resource requirements, capital cost, financing, and regulations. We must resolve them in order to undertake broad-scale plant investments in the middle 1980's for the advanced technologies mentioned earlier which are essential to achieving significant production in the 1990's.

By starting immediately, there can be several first generation synfuels plants built and operating by the time second generation technology is ready to come to our aid.

For the success of both the Demonstration and Commercial Demonstration programs, your contributions will be essential. By 1979, we will need new instruments for the first demonstration plants because in that year field construction of those early plants will start. There is a time urgency associated with these activities and I know you are equal to the challenge. In the words of Dr. Samuel Johnson, "Few things are impossible to diligence and skill". Those in this room have those qualities in abundance as well as the

intelligence to find creative solutions to problems. After all, a computer with as many vacuum tubes as a man has neurons in his head would need the Pentagon to house it, Niagara's power to run it, and Niagara's water to cool it.

Now I will end by prepared remarks. While I would like to speak for posterity, I would like to stop before my constituency arrives!

PROCESS STREAM MEASUREMENTS SESSION -- DENSE PHASE

Session Chairperson

R. R. Stalnacker
C. F. Braun and Company
Alhambra, California

REVIEW OF THE STATE-OF-THE-ART OF FLOW AND ANALYSIS INSTRUMENTS

N. M. O'Fallon, Project Leader:
Instrumentation and Control for Fossil Demonstration Plants
Applied Physics Division
Argonne National Laboratory
Argonne, Illinois

REVIEW OF THE STATE-OF-THE-ART OF FLOW AND ANALYSIS INSTRUMENTS

N. M. O'Fallon, D. Duffey, C. L. Herzenberg,
W. W. Managan, K. G. Porges, and A. C. Raptis
Argonne National Laboratory

In this talk, I will review the current state-of-the-art of instruments for process control, with emphasis on primary sensors, which measure mass flow rates and perform on-line analyses of process streams unique to coal conversion and combustion systems.[1] These streams are made up of crushed solids -- usually coal, char, or ash; sometimes limestone, dolomite, powdered iron, or alumina pellets -- moving with liquids and/or gases. They range in makeup from streams containing 50% or more by volume of crushed solids to supposedly clean gas streams containing a few ppm by volume of micrometer size particles. In the demonstration and commercial scale plants, pipe sizes will probably be as large as 10 to 15 inches diameter for solids feed streams and 3 or 4 feet diameter for gas streams. These streams are abrasive and corrosive with pressures as high as 4500 psi and temperatures to 2000°F or even higher. One could hardly imagine a more hostile set of operating conditions.

Most flow sensors do not respond directly to mass flow, which is the quantity of interest for materials balance. The relationship between mass flow and flow speed is shown in Fig. 1. The mass flow rate in units such as pounds/sec is equal to the product of the density, the flow speed, and the pipe cross sectional area. A separate measurement of density is usually needed in order to compute a value for the mass flow rate. In a multiphase stream, the different phases may be moving with different average flow speeds, which must be used with the effective density for each phase to give the computed mass flow rates of, say, the solid portion and the liquid portion of the stream. If the mass flow rates of different constituents in the stream are needed, an on-line analysis must be performed to obtain the effective density of each constituent. An example would be monitoring the carbon content of the coal feed to a gasifier in order to control the carbon, oxygen, and steam ratios in the gasifier.

Let us consider a number of types of flow sensors and briefly review experience with or expected feasibility of these flow devices for the mixed-phase process streams of coal plants.

$$M = \rho v A$$

M = MASS FLOW (LBS./SEC.)

ρ = DENSITY (LBS./FT.^{3})

v = FLOW SPEED (FT./SEC.)

A = CROSS SECTION (FT.^{2})

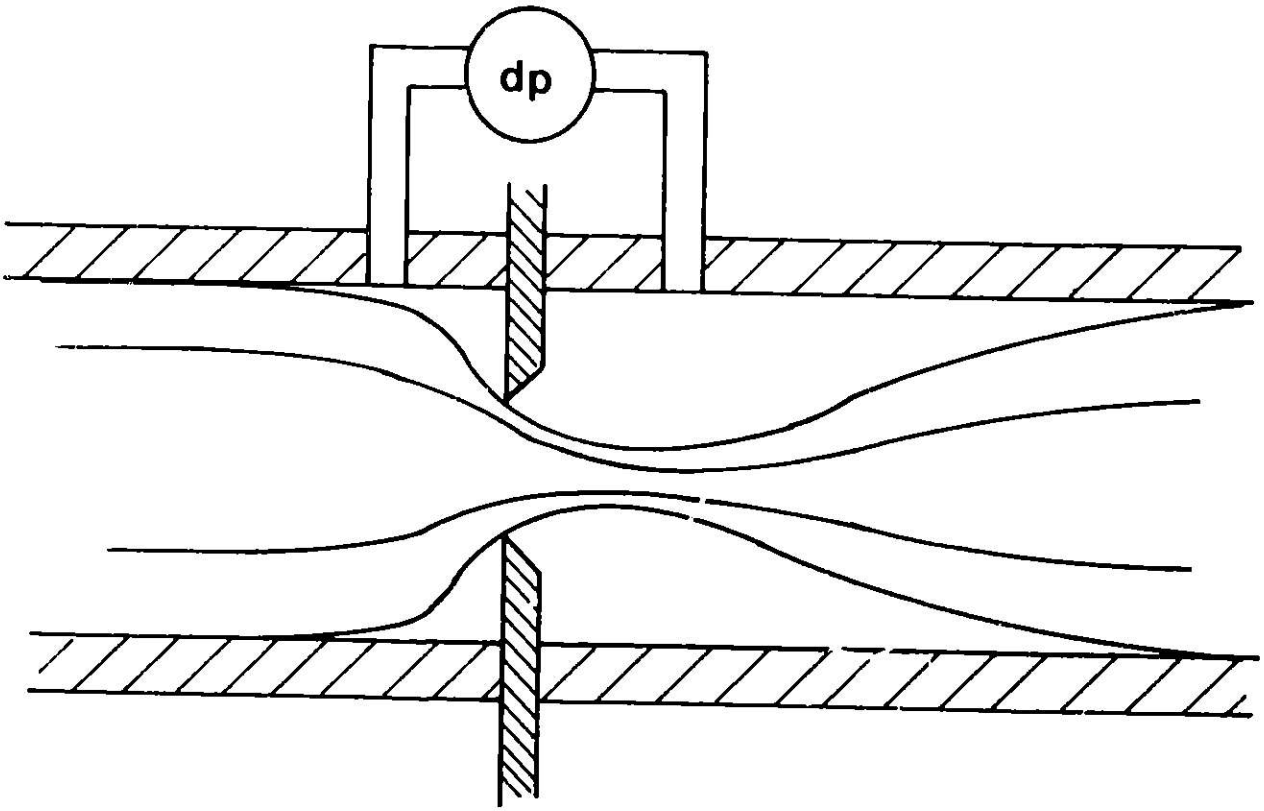
Fig. 1. Mass Flow Equation

One very common flowmeter is the head type flowmeter. An example of this type, the Orifice Meter, is shown in Fig. 2. Head type meters are characterized by a constriction of some kind in the stream and the measurement of differential pressure between the upstream and downstream sides of this constriction. In the Orifice Meter, the constriction is a plate with an opening -- often of careful design -- cut into it. In the Venturi Meter, the constriction is smoothly tapered to follow the flow contour of the emerging stream. Since the Orifice Meter depends critically on the shape of the orifice, the abrasion and corrosion in a solids-containing stream is intolerable. The main problem with head type flowmeters, however, is plugging of the pressure taps with solids.

Drag type flowmeters, such as the Drag Body Flow Meter shown in Fig. 3 or the similar Target Meter, transmit the force on an obstruction in the stream to an external force transducer. These are not suitable for mixed-phase streams because of the erosion problem. Rotameters employ a vertical tube with a tapered bore in which a "float" assumes a different vertical position for different flow rates. Again, these are not suitable for the streams we are considering because of the erosion and buildup on and around the "float". Turbine meters are essentially rotors placed in the stream so that they rotate as the stream passes it with a speed proportional to the flow speed. The same erosion problems and fouling of the bearings cause this device to be unsuitable for our needs.

In general, it can be said that any device which intrudes into the solids-fluid process stream does not operate satisfactorily because of some combination of the erosion, corrosion, and plugging problems.

There are some commercially available flowmeters which do not have obstructions in the stream. One of these is the Electromagnetic Flowmeter illustrated in Fig. 4. It operates by measuring the electromotive force induced according to Faraday's Law in a conducting medium passing through a magnetic field. The induced emf is proportional to the strength of the magnetic field and the flow speed. The stream must have a conductivity of a few micromhos/cm or more which, for coal plants, limits the Electromagnetic Meter to water-based slurries. It should work well in the few streams of this type in the coal plants, although I am not aware of any case where it has been used in this application.



HEAD TYPE METER

Fig. 2. The Orifice Flowmeter, an Example of a Head Type Meter

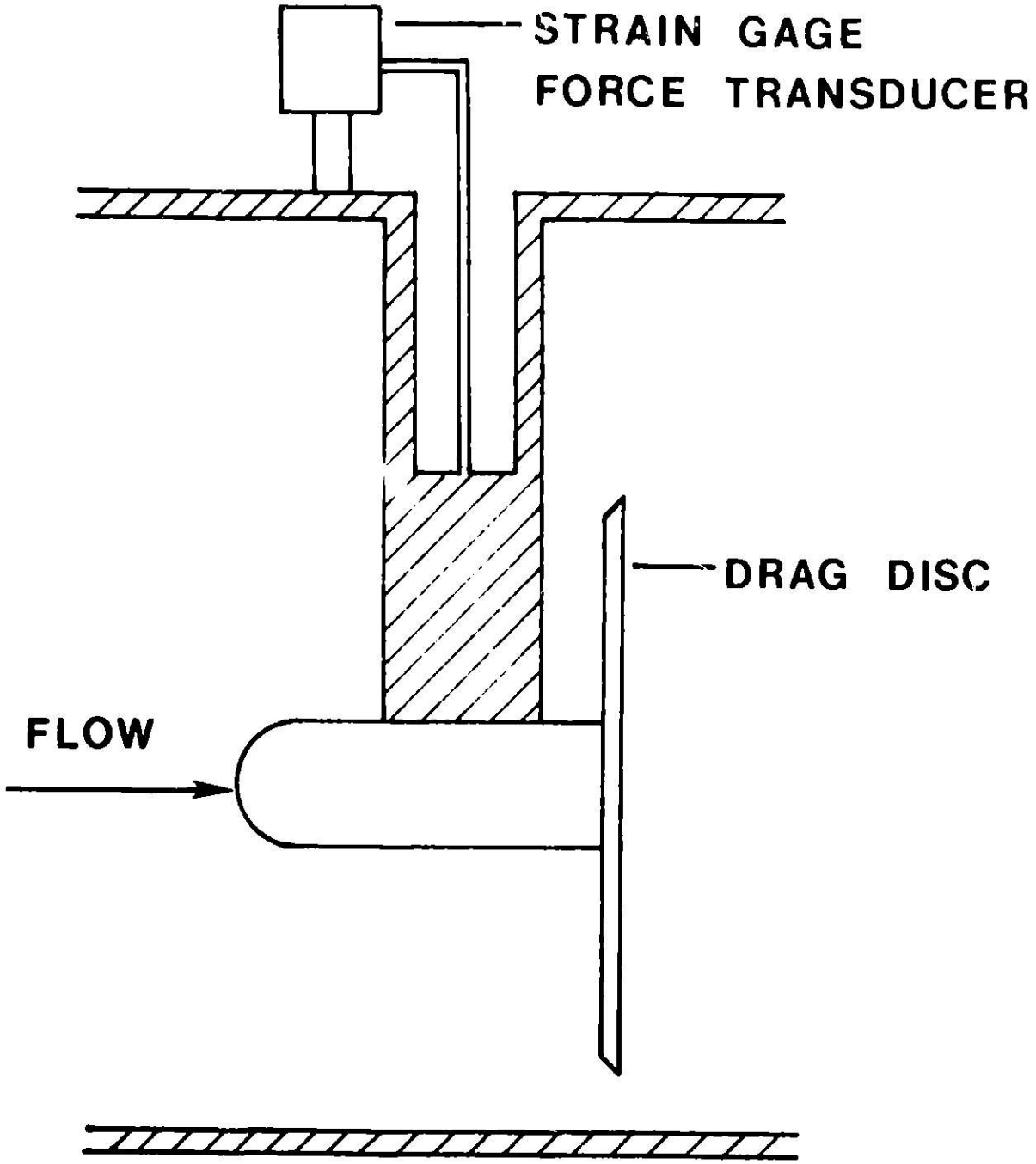
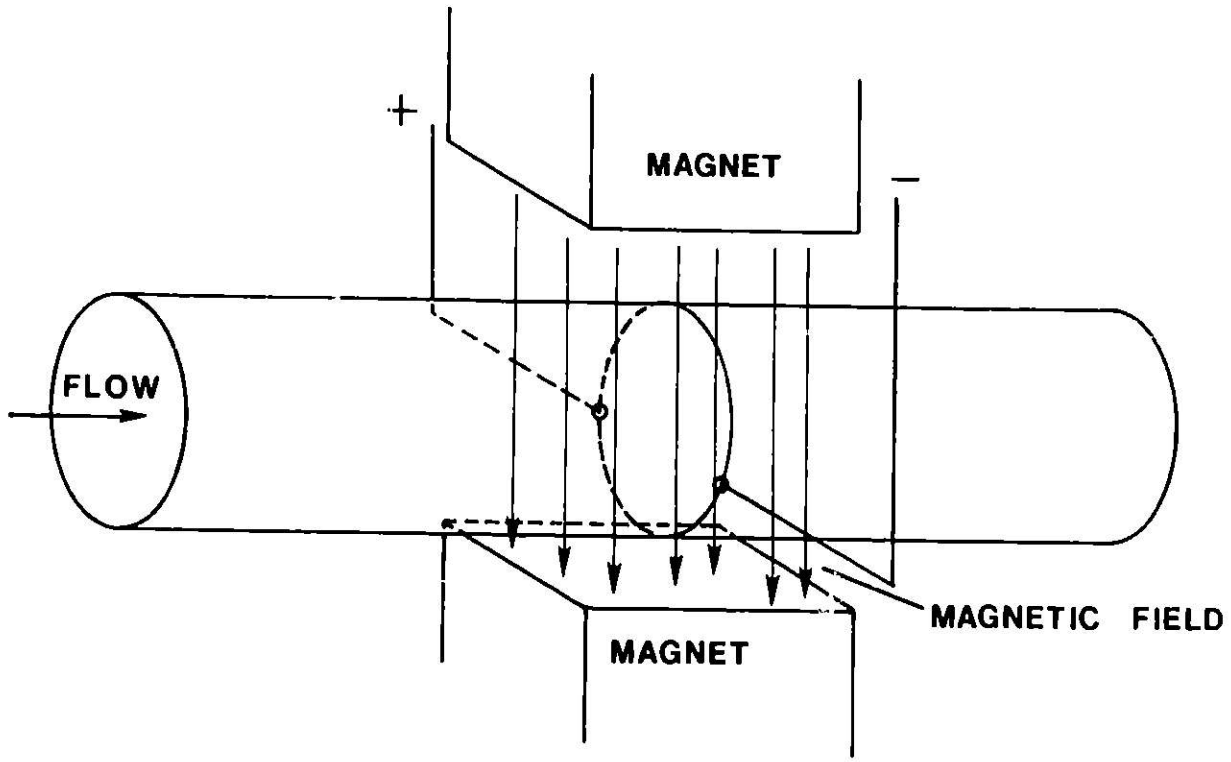


Fig. 3. The Drag Body Flowmeter



ELECTROMAGNETIC FLOW METER

Fig. 4. The Electromagnetic Flowmeter

The thermal flowmeter is also commercially available and does not introduce obstructions into the stream. It is shown schematically in Fig. 5. Typically a heater coil introduces heat into the stream and two thermocouples or resistance thermometers measure the upstream and downstream temperatures. If the heater power is adjusted to maintain a constant temperature difference $T_2 - T_1$, the heater power is very nearly linearly proportional to the mass flow. This instrument is advertised to have an accuracy of 1%, range of 10:1, temperature limit of 1500°F, and pressure limit of 60,000 psi. It is said to be able to me sure slurry flow, non-airborne solids flow, and dirty gas flow (solids not measured). A device of this kind is being tested at the BI-GAS Pilot Plant and will be reported on by John Miles in the next paper.

One type of flow instrument which is commercially available, non-intrusive, but limited as presently available to slurries of less than 8% solids by volume is the sonic/ultrasonic type. These may take several different forms. One of the simplest is the passive sonic/ultrasonic device, shown in Fig. 6, in which a microphone simply listens to the sonic signals generated by the flow and seeks to relate the intensity in one or several frequency windows to the flow conditions. A device of this type to monitor entrained sand from gas and oil wells was developed in an industrial laboratory[2] and is commercially available.[3] The operating temperature is limited to under 180°F. Further work is needed to increase the operating temperature and to test for the ability to distinguish size distribution and density of particles entrained in gas streams. Passive acoustic devices have been operated in the coal feed lines of the Synthane high Btu gasification plant and in the Exxon fluidized-bed combustion unit.

One form of active Sonic Flowmeter, shown in Fig. 7., measures the difference in transmission time upstream and downstream, from which the flow speed can be calculated. A second possibility is shown in Fig. 8., in which a sonic wave beamed upstream is reflected at a higher (Doppler shifted) frequency from the moving particles to a microphone. In any of these schemes, the success of an instrument depends on the ability to measure the time or frequency differences involved, the ability of the transducers to withstand the temperature conditions, and the ability to get sufficient signal through.

Application of sonic/ultrasonic techniques to flow measurement in coal streams is included in the coal instrumentation effort at ANL, where A. C. Raptis and co-workers have developed a feasibility criterion by which the

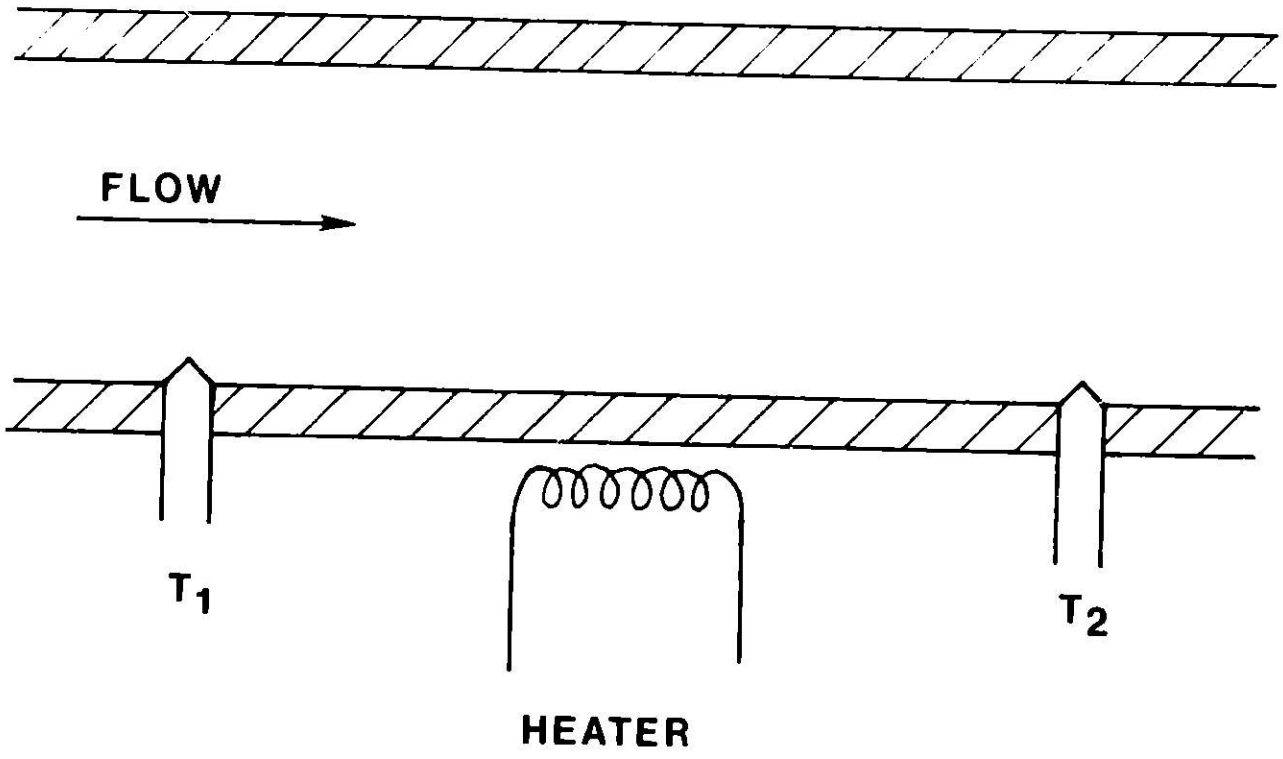
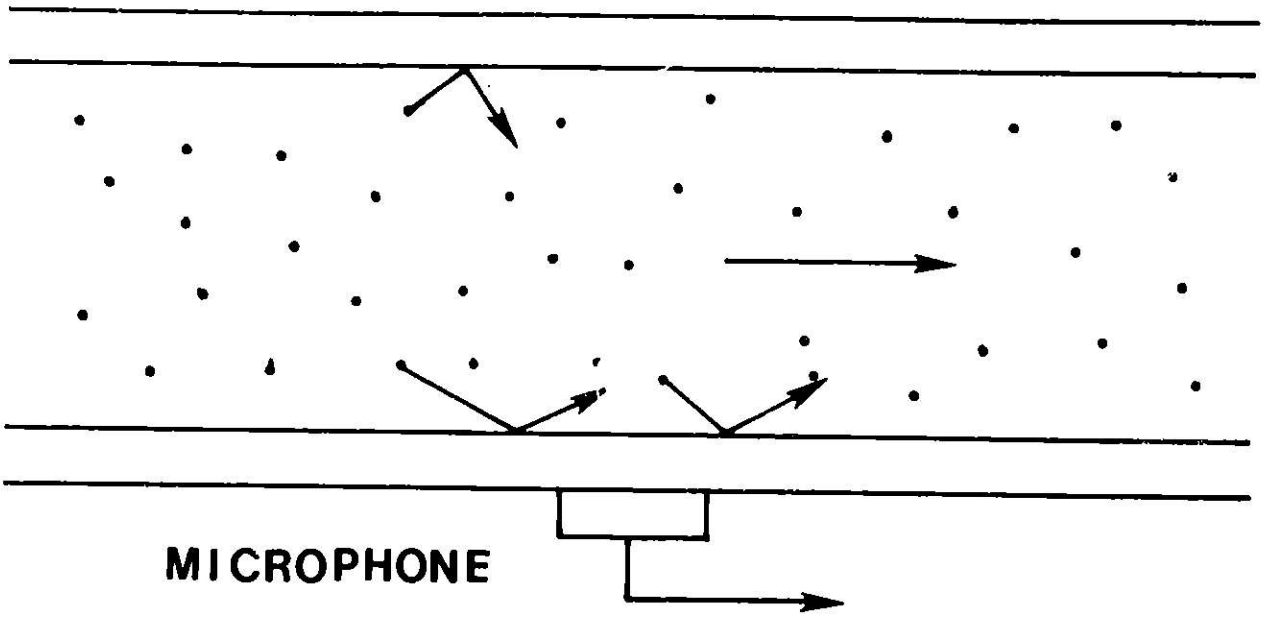
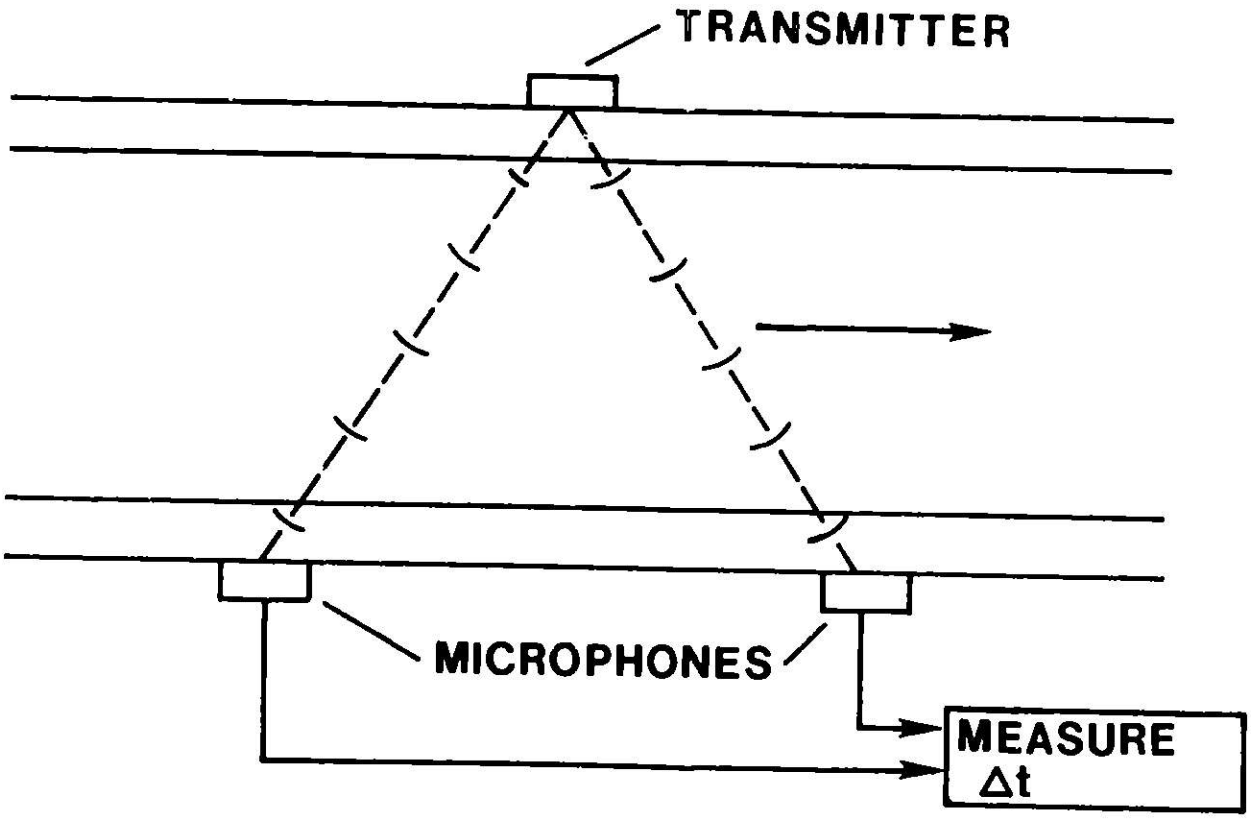


Fig. 5. The Thermal Flowmeter



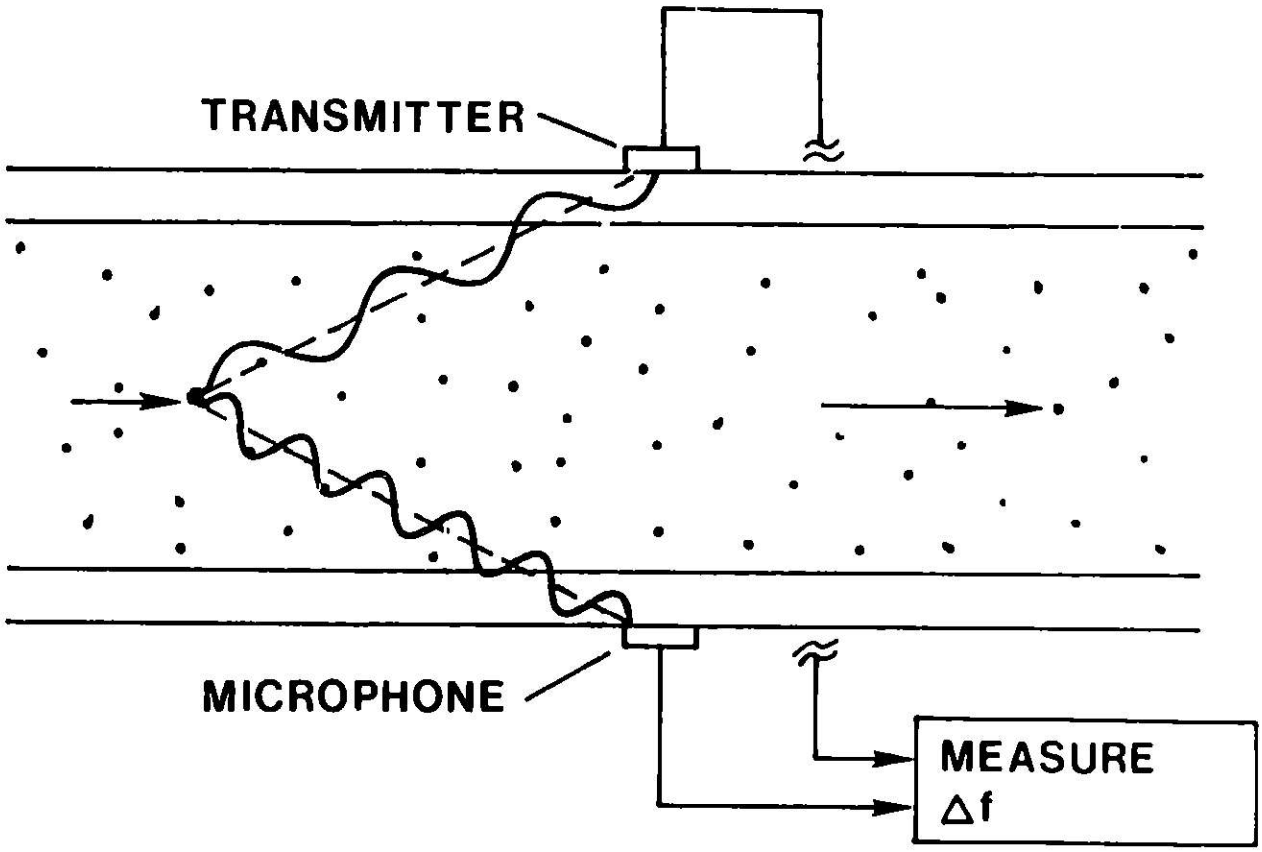
PASSIVE SONIC METER

Fig. 6. Passive Sonic Flowmeter



ACTIVE SONIC METER

Fig. 7. Active Sonic Flowmeter Based on Upstream-Downstream Transmission Time Differences



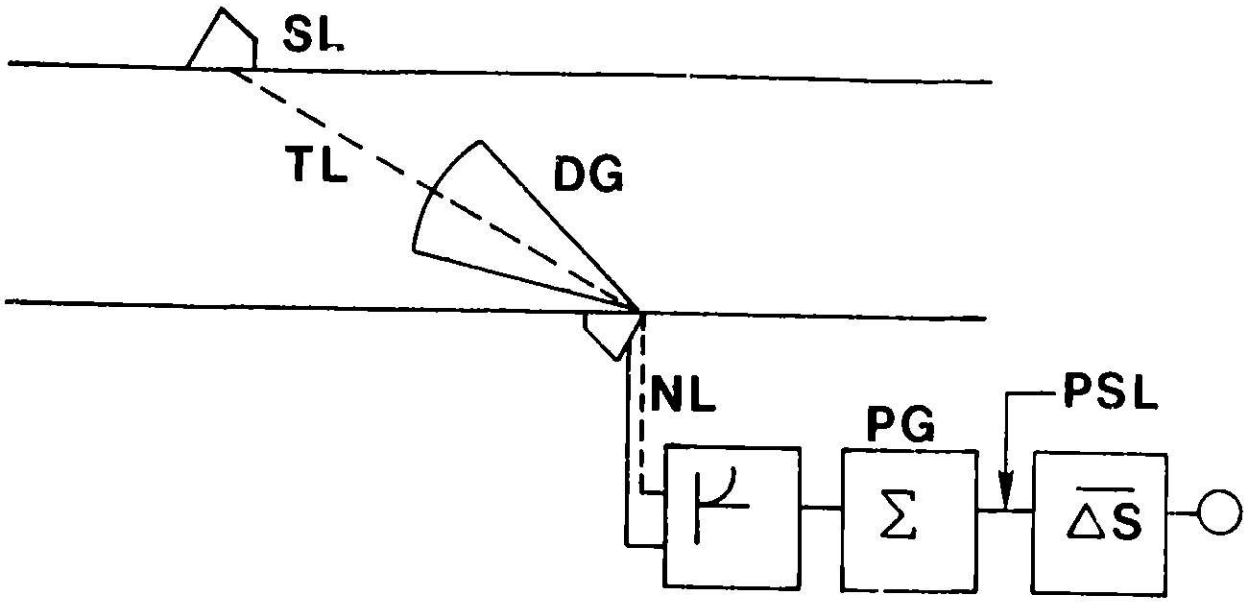
ACTIVE SONIC METER

Fig. 8. Active Sonic Flowmeter Based on Doppler-Shifted Reflections from Moving Stream

frequency range useful for a given system may be determined. The elements of the feasibility analysis are indicated in Fig. 9. The processed signal level (PSL) is required to be equal to or greater than the noise level (NL). The PSL is equal to the source level (SL) less the transmission loss between source and receiver (TL) plus the directional gain of the receiver transducer against background noise (DG) plus the processing gain (PG), the increase in signal relative to the noise due to processing.

The initial study was done for a solids-liquid non-interacting system.[4] Data for the transmission loss was taken from published measurements of attenuation versus concentration of solid particles in water at room temperature,[5] shown in Fig. 10. It is seen that below 10 to 15% volume concentration, the attenuation increases in proportion to the number of particles. Above this concentration, the particles begin to interact significantly and the attenuation actually begins to decrease as volume concentration of particles increases. Since a 10% concentration represents nearly the worst case, the transmission loss was calculated for this concentration. The other terms were estimated very conservatively based on available data. Figure 11 shows the calculated PSL versus frequency for 1 m and 10 cm diameter pipes and the estimated NL versus frequency. The lower frequency limit is determined by demanding reasonable resolution for the measurements. The flow noise curve is taken from published measurements of wall flow noise background in a circulating water tunnel.[6] For the 1 m pipe, the study indicates that the ultrasonic flowmeter is feasible for frequencies between roughly 30 and 400 kHz; for the 10 cm pipe, the corresponding frequency limits are 300 kHz and 1 MHz. Since the 10% case is chosen because of its high attenuation compared with the total range of concentrations up to 30 or 40% by volume, it is believed that these ranges of frequencies will also be feasible up to these volume concentrations of solids. Further calculations are underway to extend the study to the highest possible solids concentrations and to study gas-solids systems.

Since the values for NL have the greatest uncertainty of any of the numbers used in the calculation, preparations are underway to conduct measurements of noise background levels in the slurry feed line of the HYGAS Pilot Plant within the next few months. At the same time, data will be recorded at upstream and downstream points to be processed by correlation techniques. Laboratory tests are being conducted on representative coal



PSL = SL - TO + DG + PG

PSL - NL

SL = SOURCE LEVEL

TL = TRANSMISSION LOSS

DG = DIRECTIONAL GAIN

NL = NOISE LEVEL

PG = PROCESSING GAIN

PSL = PROCESSED SIGNAL LEVEL

Fig. 9. Elements Used in the Feasibility Study of Sonic/Ultrasonic Techniques for Measurement of Flow of a Multiphase Stream

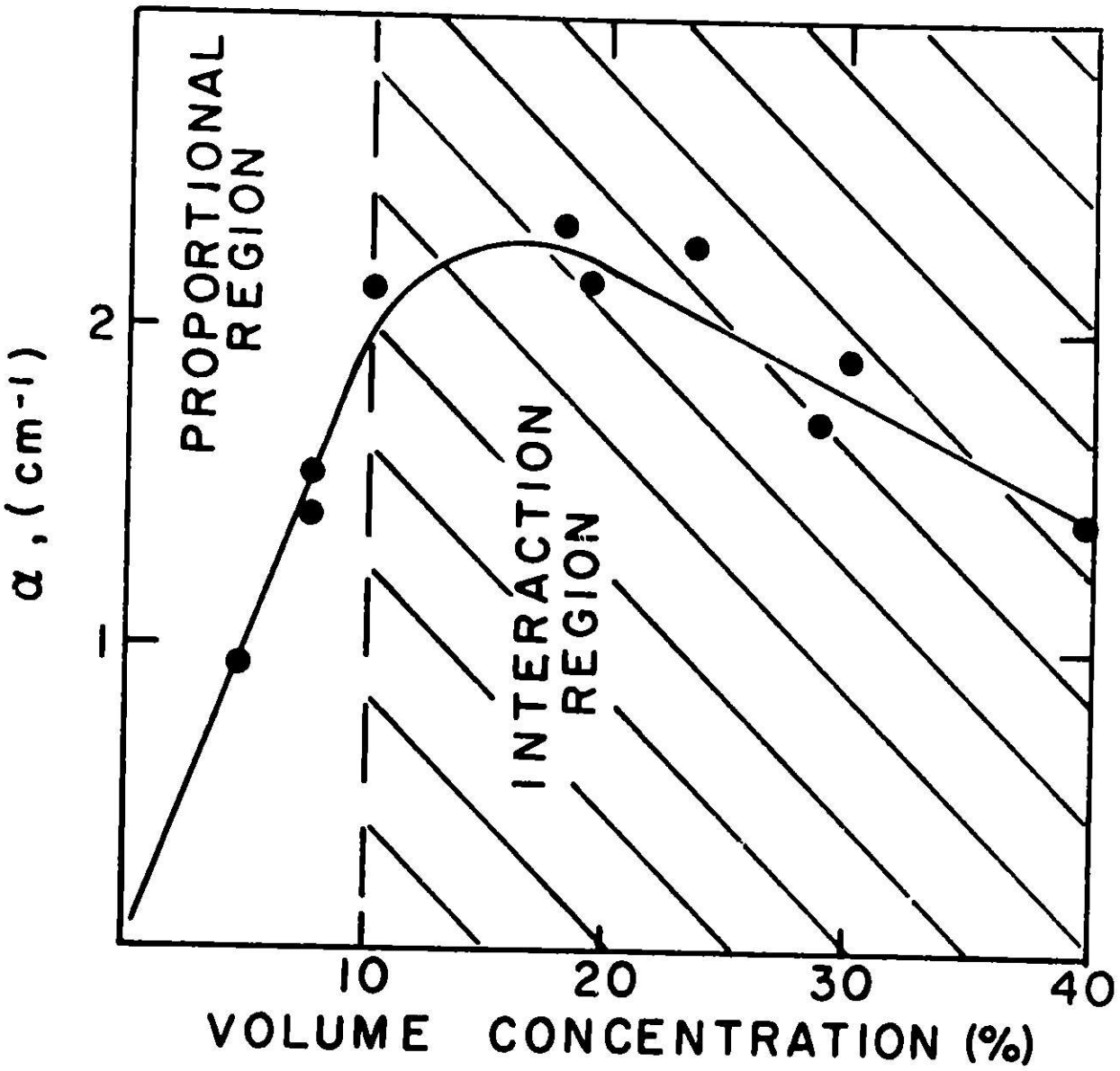


Fig. 10. Published Data for Attenuation of Sound as a Function of Concentration of Solid Particles in Water

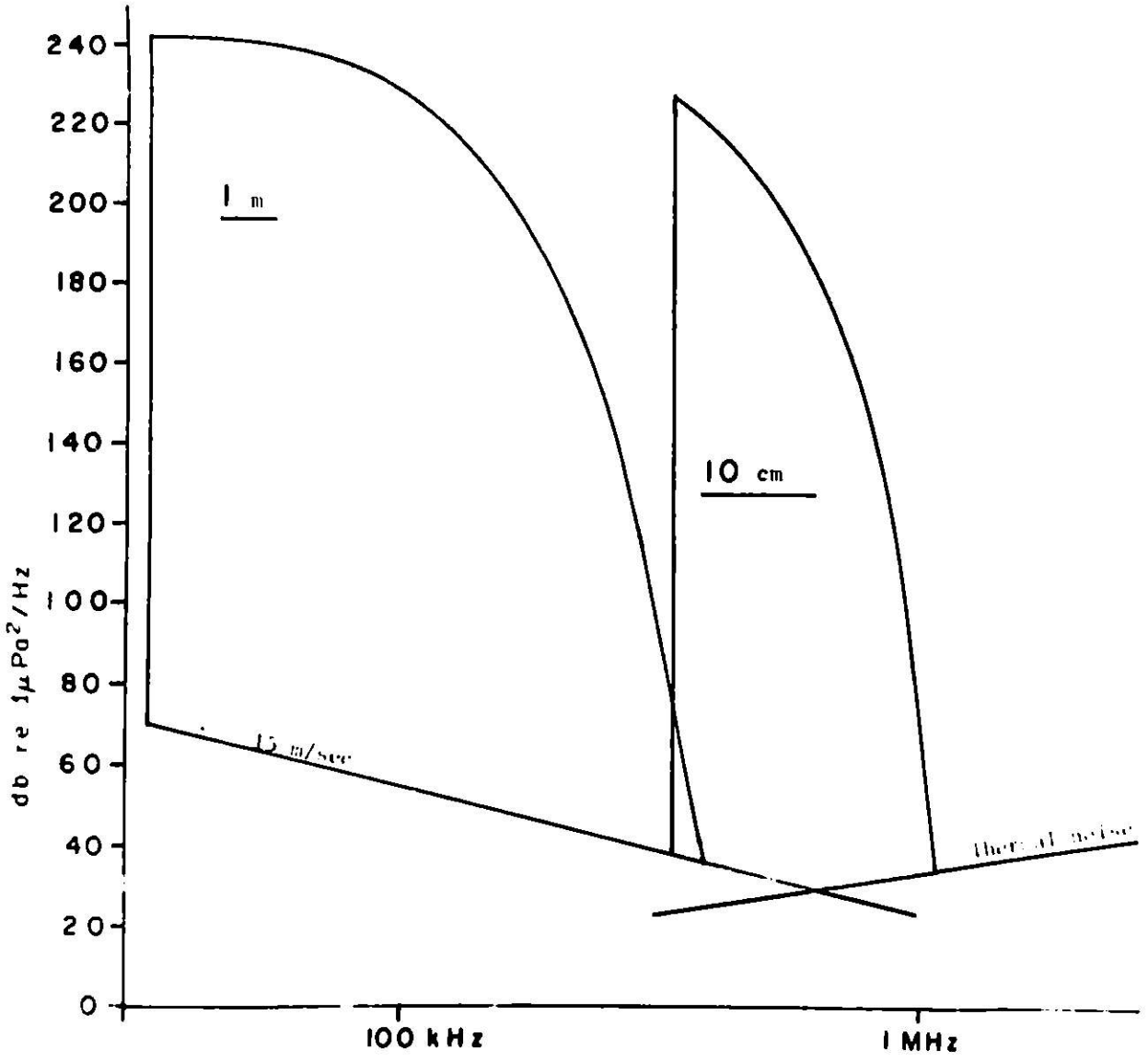
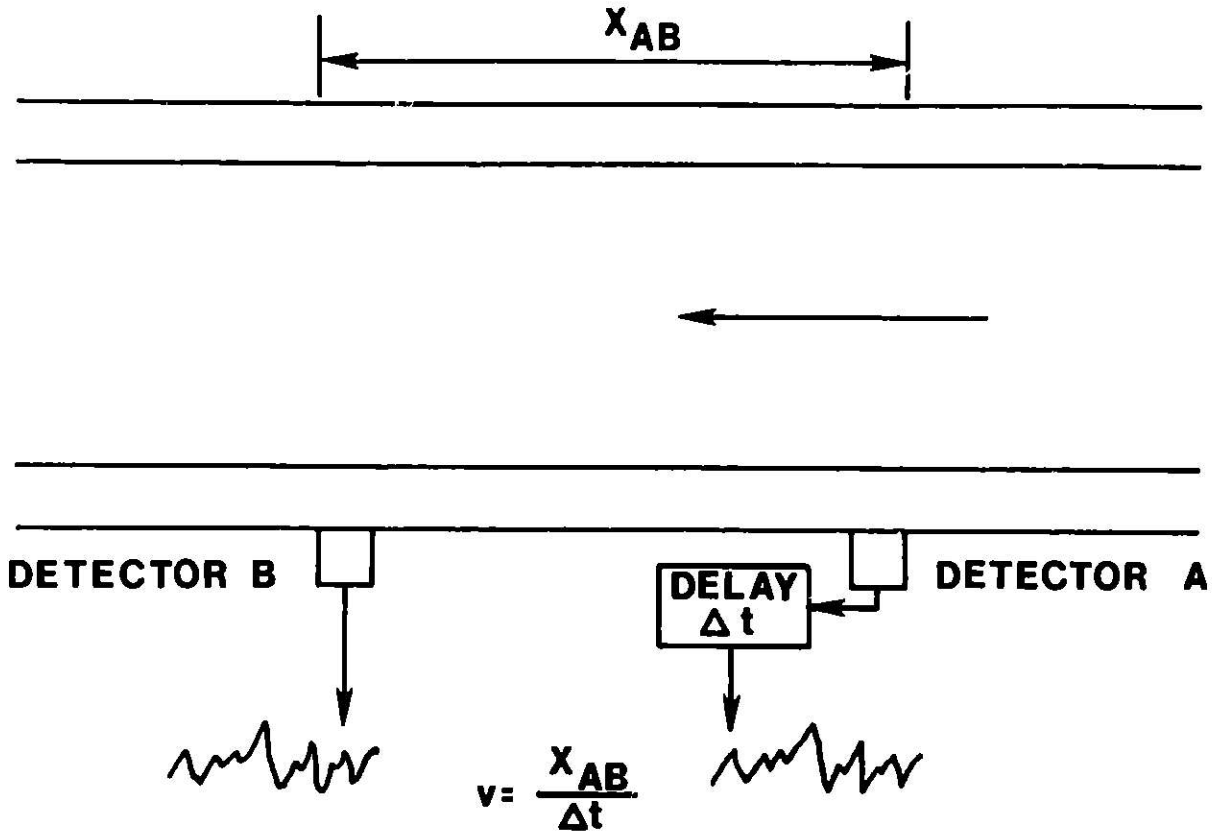


Fig. 11. Calculated Processed Signal Level versus Frequency for Two Pipe Sizes

process samples to determine parameters for the actual system of interest and to verify results of the feasibility calculations.

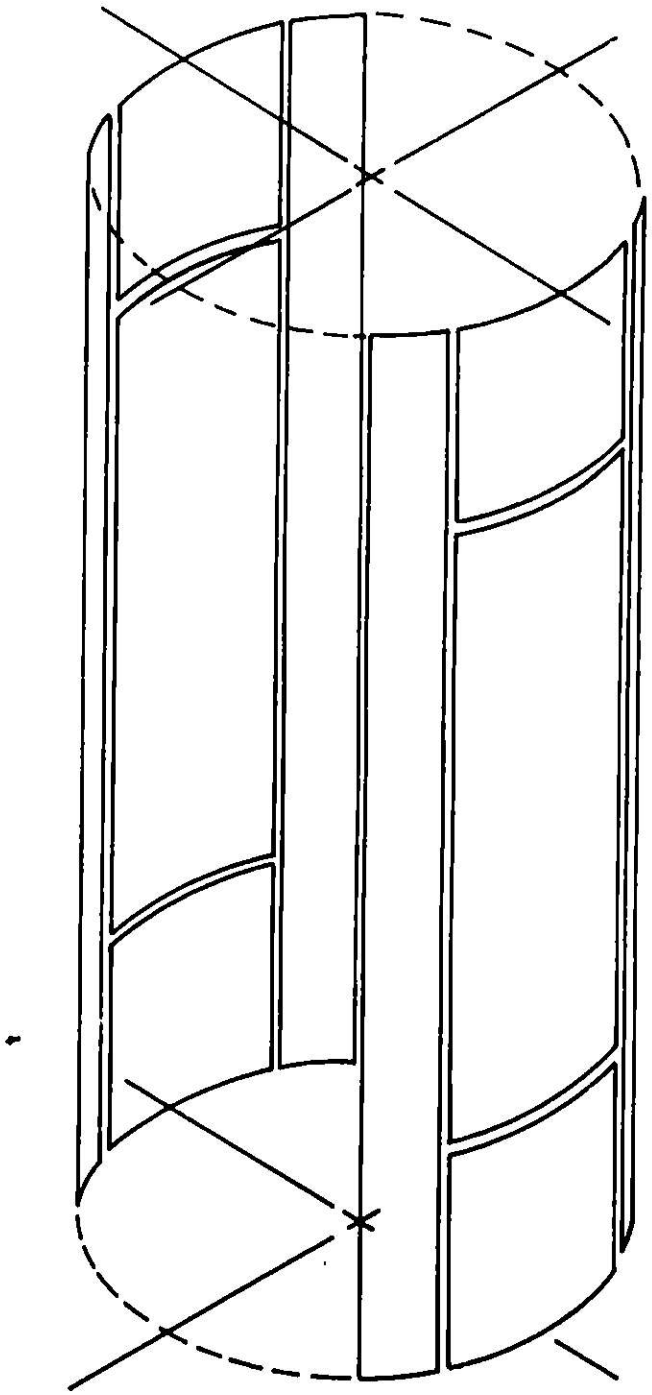
The correlation technique for flow determination is illustrated in Fig. 12. The basic idea is applicable to almost any pair of identical sensors and assumes that the system variable being measured will have local variations within the stream which will persist within the flowing medium long enough to be seen by detector A and later by detector B when the material has traveled from A to B. Mathematical comparison or correlation of the two signals as a function of the time delay of signal A will exhibit a maximum when the time delay corresponds to the transit time of the stream from A to B. Dividing the known distance between the two detectors by the transit time yields the flow speed. This technique has been used for many years as a calibration method, but only recently have electronic devices become available which can perform the necessary calculations fast enough to make such a device an "on-line" type of instrument. A device has recently been developed by industry in Canada based on ultrasonic cross correlation to measure heavy water flow.[7] Preliminary work at ANL by K. G. Porges indicates that a correlation device based to two gamma ray density gauges can be developed, using state-of-the-art electronic components, to give a calculated mass flow value, using the measured density, with an accuracy of ∿2% in about 2 or 3 seconds. An early prototype is being built for testing on the HYGAS Pilot Plant cyclone dipleg within the next few months.

Another technique being investigated at ANL by W. W. Managan, both as a means of density or solids-fluid ratio measurement and, via correlation, for flow measurement, is capacitive density. In this device, capacitor plates are embedded in a ceramic liner of the pipe so that the material within the pipe will cause the measured capacitance to increase in proportion to the amount of material present and its dielectric constant. Fig. 13 shows the general arrangement of capacitor plates. The central plates are the sensing elements while the surrounding guard plates are designed to eliminate fringing effects on the central plates. A bench system for testing this concept and designing optimal plate configurations is shown disassembled in Fig. 14. In the rear is a lucite cylinder around which the plates, shown in the front, are arranged. The split outside lucite cylinder is shown with the electrical cables. In Fig. 15, the assembled system is shown. The material to be



CORRELATION FLOW METER

Fig. 12. Correlation for Flow Measurement



CYLNDRICAL CAPACITOR ELECTRODE CONCEPT

Fig. 13. Capacitor Plate Arrangement for Density and Solids/Liquid Ratio Measurement

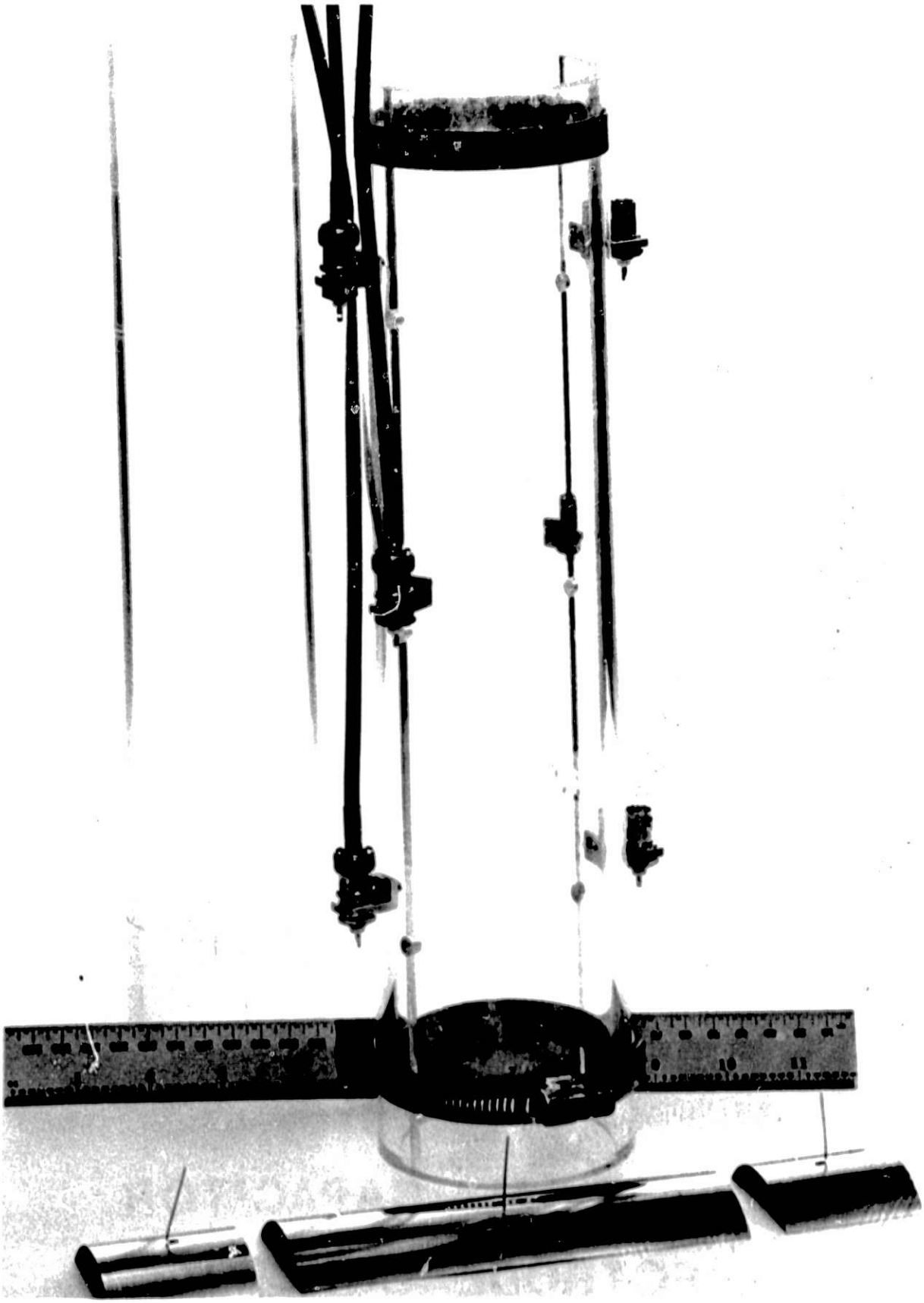


Fig. 14. Disassembled Bench Scale Capacitive Density System

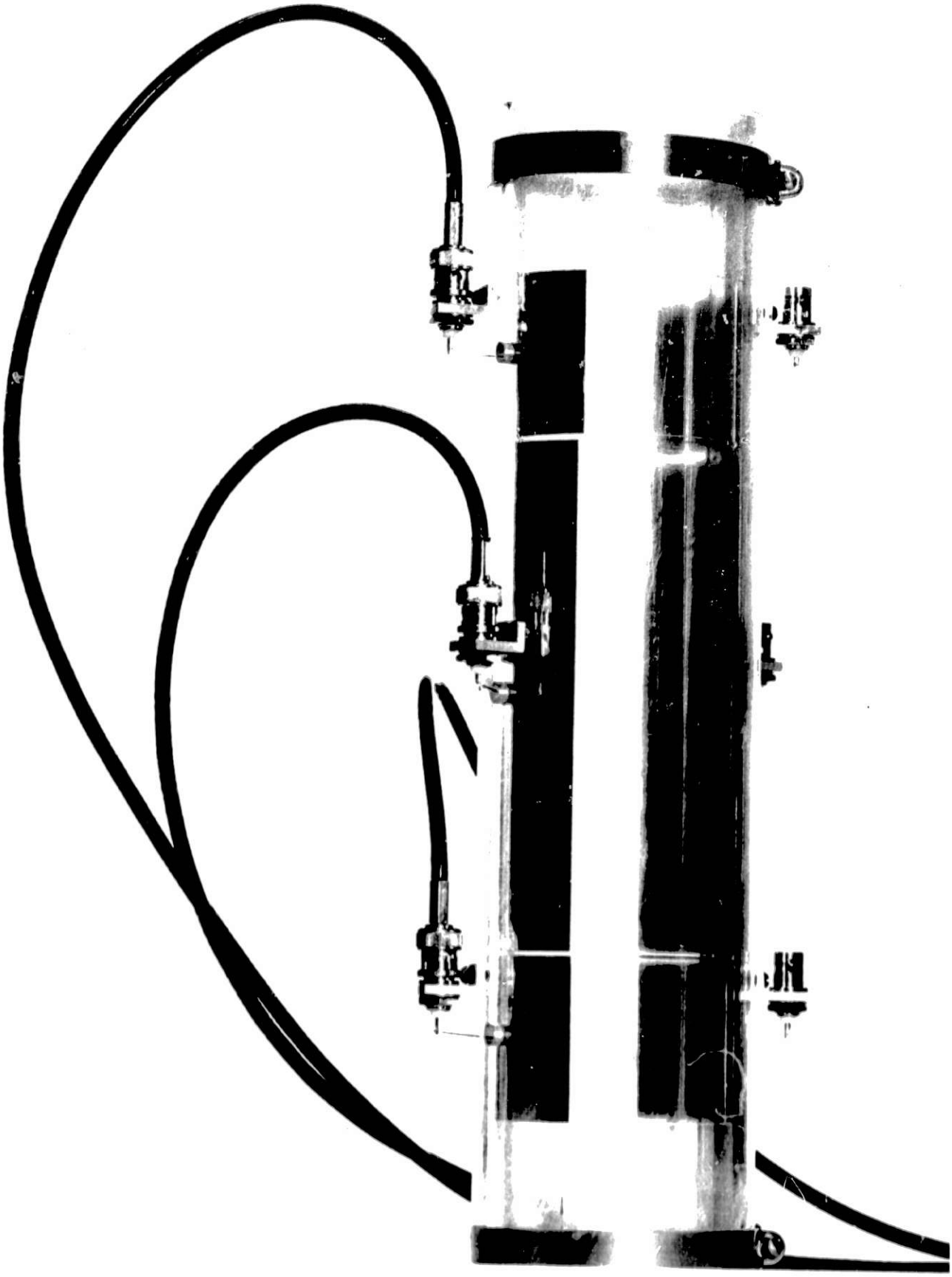


Fig. 15. Bench Scale Capacitive Density System Assembled

measured is placed in the inside. Recent studies with the system surrounded by a metal pipe, as would be the case in a coal plant, have led to a design with the central plates surrounded by a series of narrow plates at successively lower potentials, which serve to shield the measured volume from the effects of the pipe. A system is being fabricated for installation and testing in the HYGAS slurry line in tandem with the ultrasonic instrument. The capacitive tive spoolpiece will contain electrodes designed to produce a relatively uniform field across the pipe for a length of several pipe diameters to measure average solids-liquid ratio, as well as separated smaller electrodes designed to respond to local fluctuations to measure flow speed by correlation methods. Plans are also underway to test a system of this type in the char return line of the BI-GAS plant.

One of the difficulties that we and others have found in adapting, testing, and calibrating instruments for measuring flow in solids-fluid systems is the lack of a facility in which such flow can be maintained and controlled. Therefore, we are constructing a loop which we call the intermediate Solids/Gas Flow Test Facility (S/GFTF), a room temperature non-pressurized system to circulate crushed coal, char, or other solids with air or other gas to provide conditions simulating those in coal plants -- at least as far as flow rates and solids concentrations are concerned. It is shown in Fig. 16. It consists of two storage hoppers mounted on electronic scales for direct mass readout and accurate measurement of mass flow. A calibrated orifice permits variation in test region 1 up to approximately 1 lb/sec in the vertical down leg test region from hopper 1. The known solids flow is pneumatically conveyed through test region 2. Switching of this flow to the cyclone entry of hopper 1 gives a steady state mass flow over extended periods with low accuracy for a setup mode of operation. In this mode, the gas exiting cyclone 1 flows through test region 3. If the rotary feeder at the bottom of hopper 2 is closed, the scales on hopper 2 will measure the particulate mass flow through region 3 for calibration of particulate monitors. Otherwise the rotary feeder will return the fines to the circulating flow. Switching the flow to the cyclone of hopper 2 provides short term (300 - 500 sec) mass flow out of hopper 1 of 300 - 500 lbs with an accuracy of 1 lb or less. The system is built with 3 in. pipes, but fittings permit installation of pipes up to 6 in. diameter. The facility

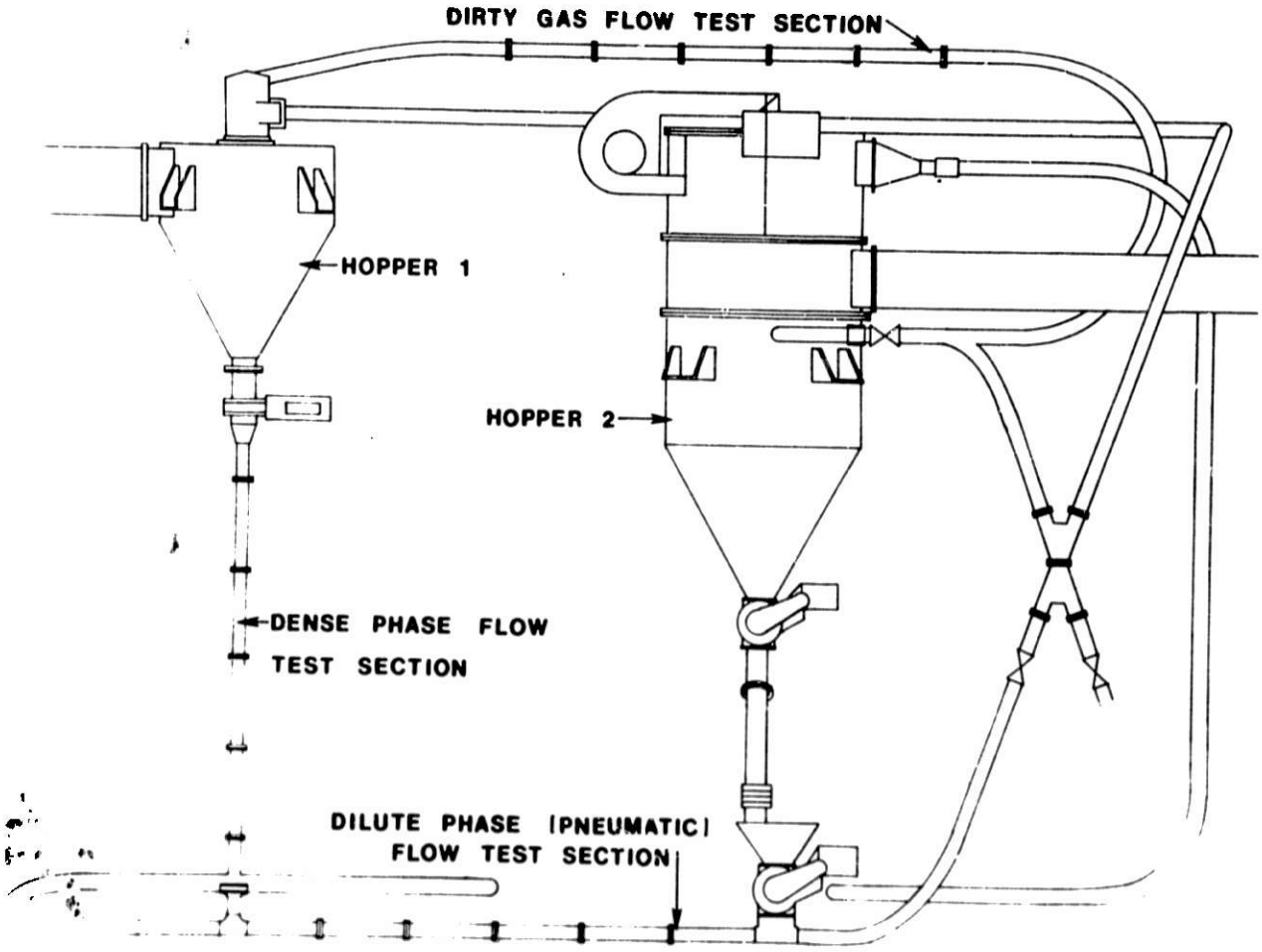


Fig. 16. ANL's Intermediate Solids/Gas Flow Test Facility (S/GFTF)

is scheduled for completion within three months. Other loops for circulation of solids-liquid slurries and for operation at temperature and pressure are being designed.

The hopper weighing technique is expected to work well here because it is possible to have comparable weight between the hopper and its contents, and, because of the low temperature low pressure operation, it is possible to minimize forces between the hopper and connecting pipes. In a large coal conversion plant, where heavy walls would be required to withstand the pressure, and temperature variations will affect the weight on the load cells, such a system will lose a great deal in accuracy. It should be noted also that the process is inherently discontinuous as the hopper has to be filled periodically.

Several devices are commercially available or under development for monitoring particulate loading of gas streams by optical scattering methods.[8] Two of these will be discussed tomorrow by E. S. VanValkenberg and J. D. Trolinger.

Consideration of available techniques for on-line analysis will take much less time, partly because there seem to be so few possibilities. A number of processes depend on gas chromatography for an almost on-line analysis of gas streams. A gas chromatograph, indicated schematically in Fig. 17, uses a carrier gas to transport a gas sample, which may come from a switched-in side stream from the process, to a column. This column is chosen for the specific compounds of interest to absorb or adsorb them and then release each component at a different time. Knowledge of the properties of the column for time of release of different compounds allows the detection and quantification of these compounds. A typical chromatogram is shown in Fig. 18. The detector response peaks as each compound of interest is released by the column.

This device is sometimes used in conjunction with a mass spectrometer, which further aids identification of the compounds. A major problem with the chromatograph is that it cannot be used as an element in a control loop because it tells what happened five to fifteen minutes ago. In addition, it does involve sampling and conditioning of the sample so that the material analyzed may differ from the material in the process stream. Experience in

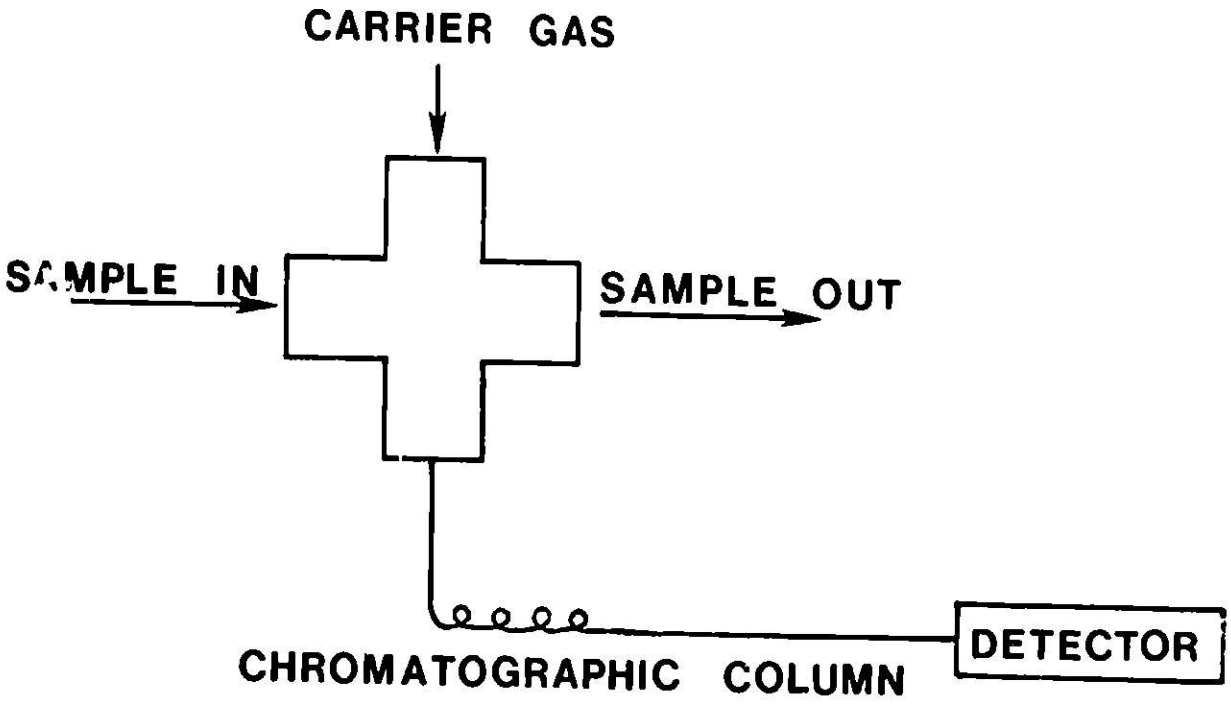


Fig. 17. Schematic of a Gas Chromatograph

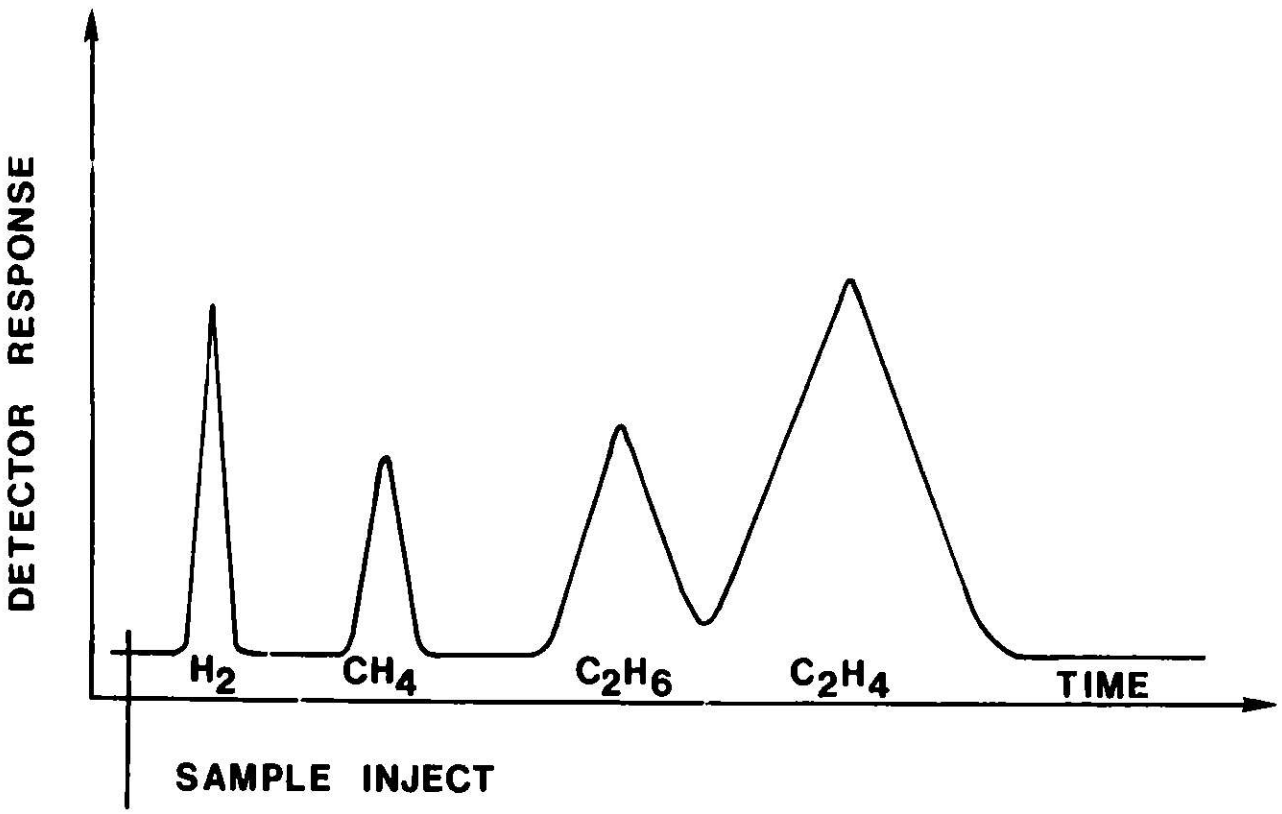


Fig. 18. Typical Chromatogram from a Gas Chromatograph

coal plants shows that the device can be made to give useful results, but only when a good deal of time is devoted to taking care of it.

A number of devices based on emission or absorption of electromagnetic radiation are able to, or show promise of being able to, perform on-line analysis of molecular or elemental composition. The part of the electromagnetic spectrum with which we are most familiar is indicated in Fig. 19. The energy of the electromagnetic radiation is proportional to the frequency, and the energy of the radiation a system will emit or absorb is determined by the possible energy levels in which the system can exist. Figure 20 indicates a generalized energy level diagram. The system has a lowest energy state, called the ground state, whose energy is represented by E_o. If it is given energy by some means, it will move to a higher energy level, say the second excited state at energy E_2. It is then able to radiate this energy by falling back to a lower state, say, the ground state and the energy of the radiation will be equal to $E_2 - E_o$. Such a system is able to absorb electromagnetic radiation of the appropriate energy as illustrated. For gamma ray emission and absorption, the energy levels would be those within the atomic nucleus; for X-rays, atomic inner electron levels; for ultraviolet, ionization of atoms and molecules; ultraviolet to visible, outer electron levels; and infrared, molecular vibration. These regions overlap a great deal. In each system, the particular set of energy levels is unique to that system, and observation of corresponding emission or absorption is proof of the presence of that system. We can thus expect to be able to learn something about the different nuclei present by gamma ray methods; something about atoms present by the X-ray, ultraviolet, visible portion of the spectrum; and something about molecules present from the ultraviolet, visible, to infrared spectrum. Only electromagnetic radiation of gamma ray energies or greater is sufficiently penetrating to go through any significant amount of solid or liquid matter. Therefore, the X-ray, ultraviolet, visible, and infrared techniques will be limited to on-line analyses of gases and laboratory analysis of solids or liquids. John Walsh will be speaking tomorrow on optical analyses of gas streams, so I will leave it for him to go into detail on this.

Now in order to do on-line analyses of solids or liquid streams, a way must be found to make the nuclei in the stream emit gamma rays. A very attractive method of doing this is to bombard the stream with neutrons,

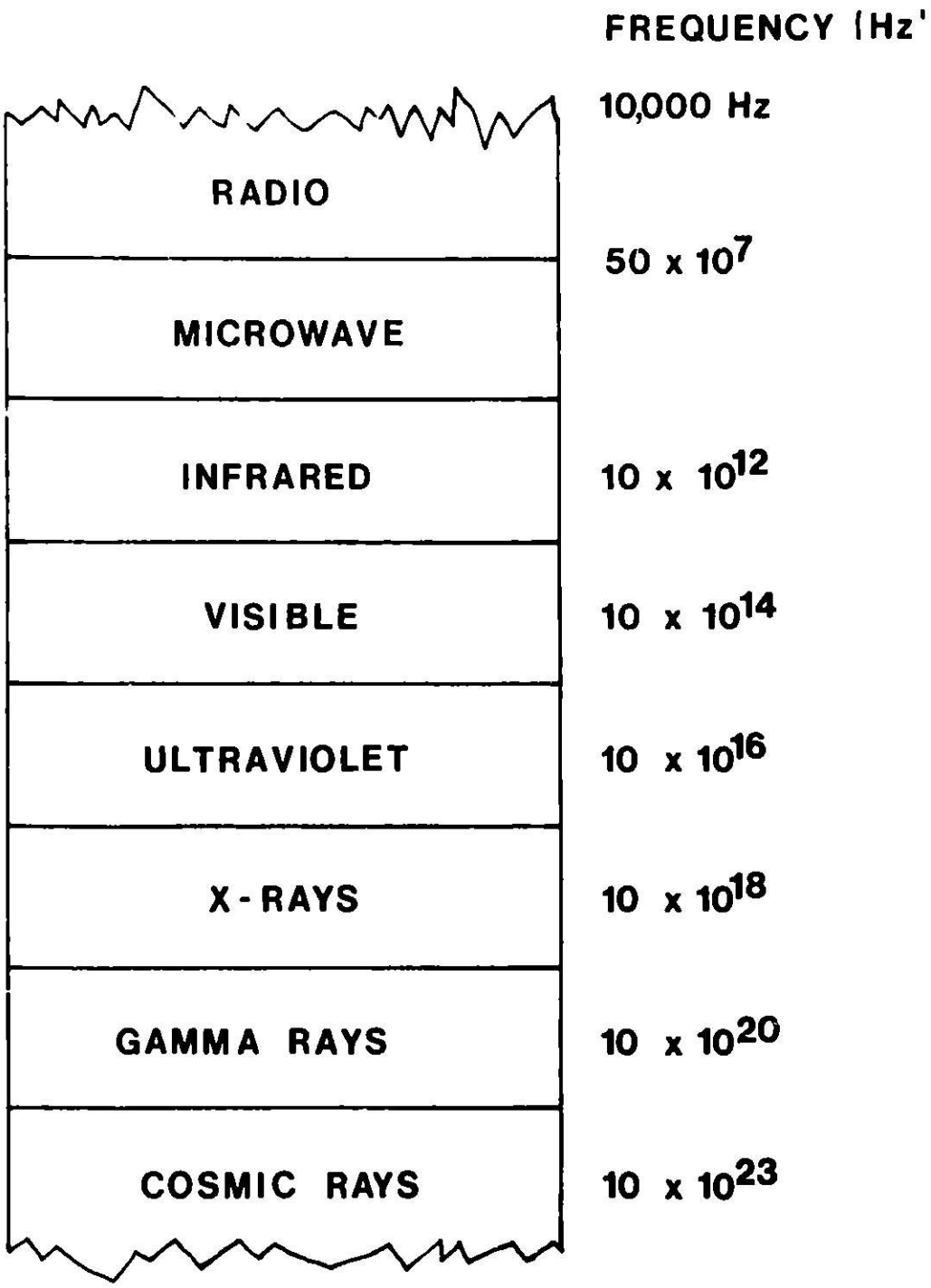
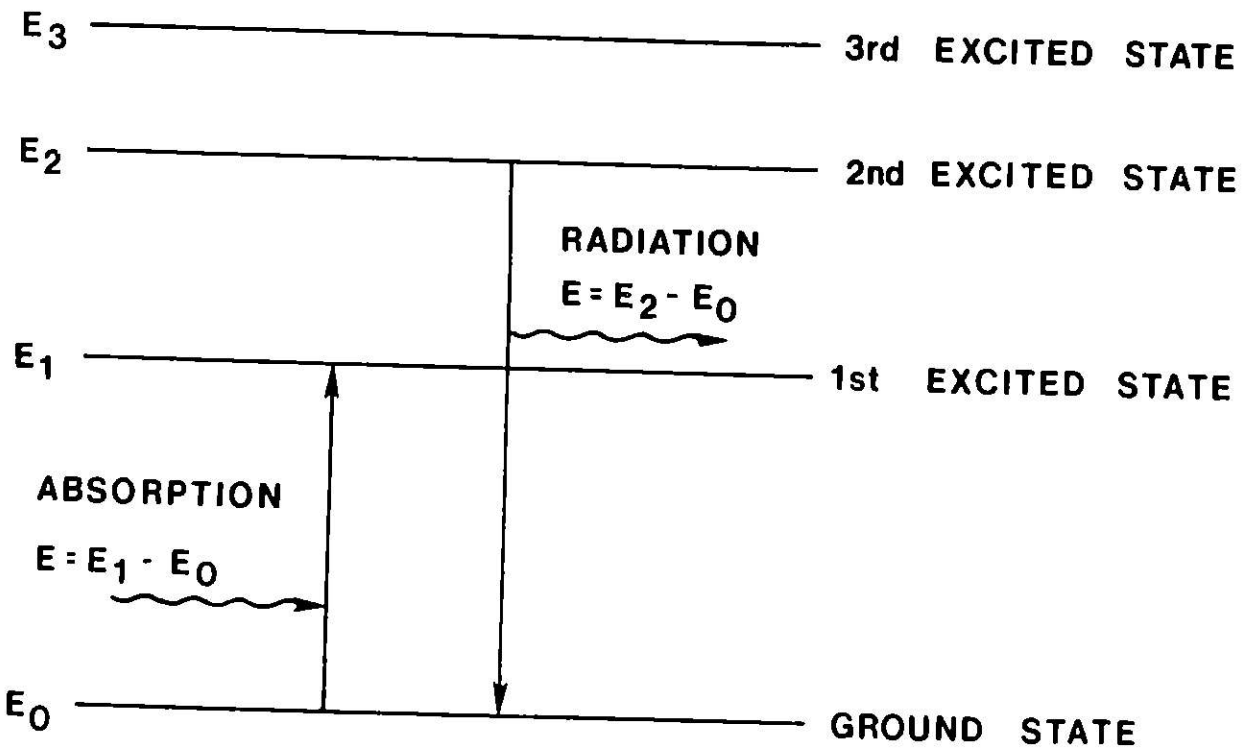


Fig. 19. The Electromagnetic Radiation Spectrum



ENERGY LEVEL DIAGRAM

Fig. 20. Generalized Energy Level Diagram

either from a radioactive neutron source or from a neutron generator of the kind used in well logging. The neutrons, being uncharged, are able to penetrate several inches or more into the sample. They can then interact with the nuclei present in several ways. In Fig. 21, two kinds of reactions which produce gamma rays promptly are shown. The first is neutron capture where, in the example, a sulfur 32 nucleus captures a neutron and becomes a sulfur 33 nucleus in an excited state. When it promptly decays to the ground state, it emits an energetic gamma ray which is a signature that sulfur 32 was present. Normally this neutron capture process is most likely for very low energy neutrons. The second example illustrates inelastic scattering of a neutron from carbon 12. The neutron bounces off having left some of its energy behind to raise the carbon 12 to an excited state. For this kind of process to occur, the neutron must have at least enough energy to give the nucleus, to raise it to its first excited state.

In some cases of neutron capture, the product nucleus may be radioactive and decay by particle emission to an excited state of another nucleus. When this final nucleus emits a gamma ray in falling to its ground state, we have delayed gamma emission. The aluminum 27 captures the neutron to become aluminum 28 in an excited state. After dropping to the ground state, the aluminum 28 beta decays (emits an electron) with a half life of 2.3 minutes to become silicon 28 in its first excited state. Yet another type of reaction is shown in which a neutron hits an oxygen 16 nucleus and knocks out a proton leaving nitrogen 16, which beta decays with a 7 sec half life to an excited state of oxygen 16. The oxygen 16 drops to its ground state with the emission of a very high energy (easily detectable) gamma ray. This reaction requires a neutron of about 10 MeV. Since a neutron generator can deliver neutrons of 14 MeV, it is easily possible to make use of this reaction.

Now some very interesting things can be done using reactions of the kind just discussed. The prompt gamma rays can be used for on-line elemental composition determination. Several groups have shown this possibility.[9] R. F. Stewart has developed an on-line sulfur meter for coal which he will give a presentation on at the Thursday evening Show and Tell Hardware Display. He has also shown feasibility of an on-line moisture meter for coal. T. Gozani will present a paper in this session on his work for EPRI developing an on-line

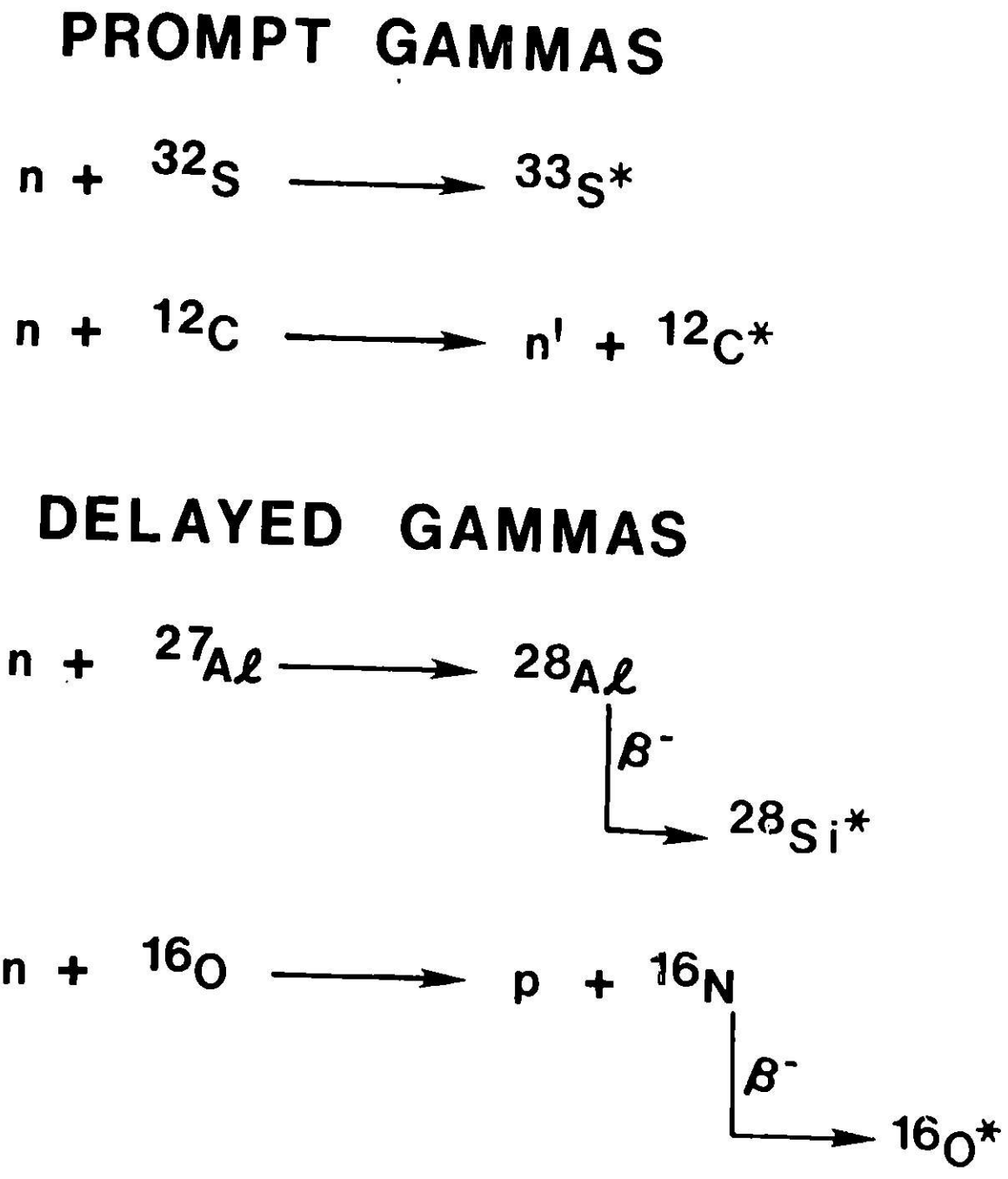


Fig. 21. Examples of Reactions in Which Gamma Rays are Emitted Following Neutron Irradiation

composition analysis for coal input to a power generation plant. At ANL, C. Herzenberg, D. Duffey, and I have been working on adapting the technique for on-line analysis through pipe walls so that it could be used for the high temperature high pressure process streams in a coal conversion or advanced combustion plant. Our work using californium 252 sources of neutrons is encouraging. Figure 22 shows some preliminary results for iron, silicon, and sulfur in synthetic coal samples. Ultimately we hope to be able to measure carbon to ash ratio, sulfur, hydrogen, moisture, and such things as catalyst poisons on-line.

Another interesting possibility which we are pursuing presents itself with the delayed gammas. If the radioactivity is induced at one point in the stream by, say a pulsed neutron generator, it can serve as a tracer to be used for flow speed determination. In addition, it can serve as a sensitive on-line means of oxygen determination in these process streams.

Finally I want to mention on-line Btu monitors for gases which have begun to be marketed in this country. They are essentially calorimeters which burn gas from a small side stream. They are advertised to have 1.5% f.s. accuracy and would appear to be useful for monitoring Btu content of synthetic fuel gas, but I am not aware of any experience with this device in these systems.

There is clearly a great deal of work to be done in the areas of instrumentation for mixed-phase mass flow measurement and on-line analysis. Cooperation among the many types of organizations and people represented at this Symposium will be required to finish the work in time for the large scale coal conversion and combustion systems our country needs to help meet its energy shortage.

Thank you.

The authors wish to thank Bela G. Liptak for the use of several illustrations from *Instrument Engineers' Handbook*, Chilton, Philadelphia (1969).

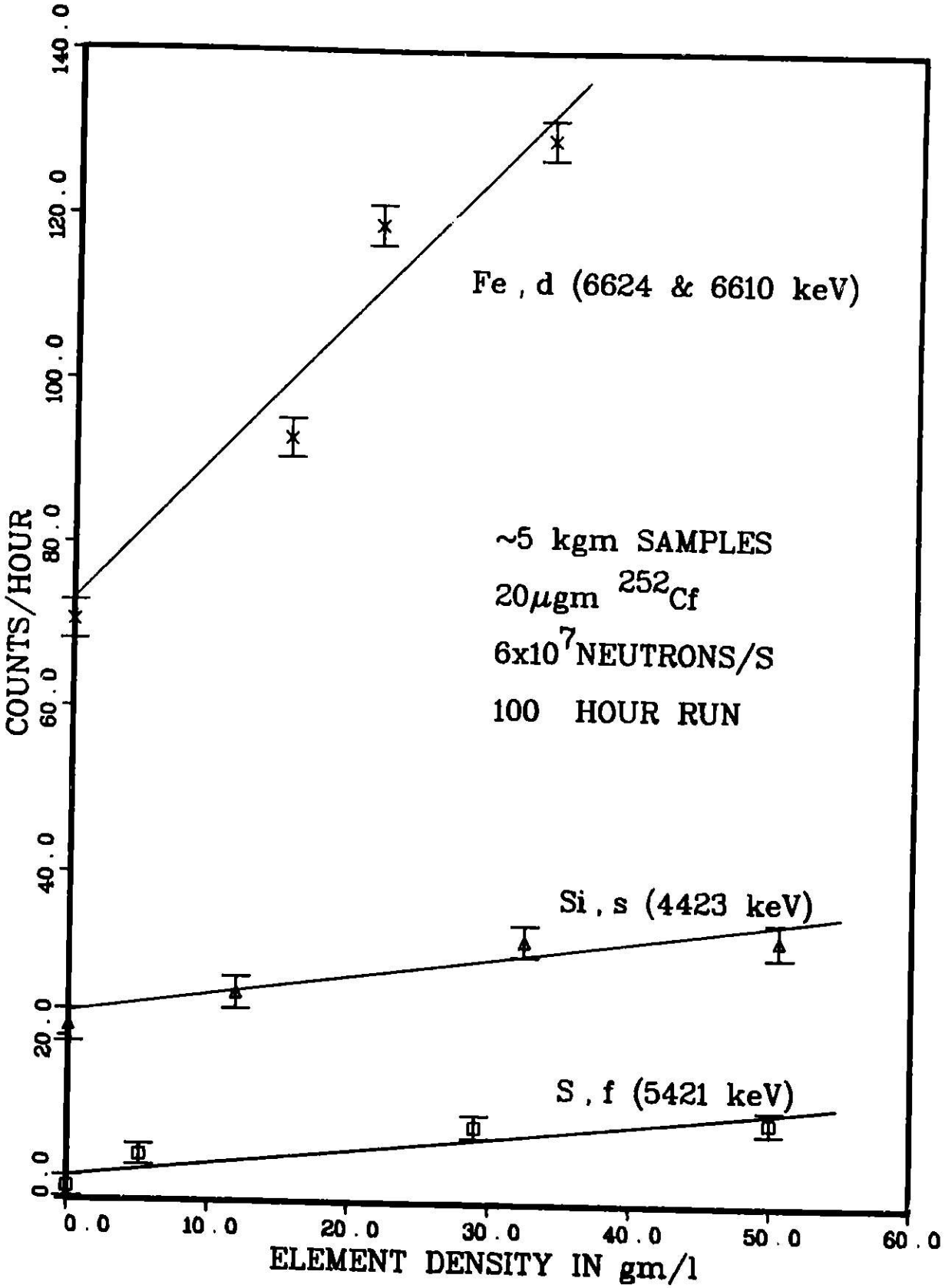


Fig. 22. Response versus Concentration for Elements in Simulated Coals

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QUESTIONS AND ANSWERS

N. M. O'Fallon

Argonne National Laboratory

J. H. Vignos, The Foxboro Company

Q. What coherence lengths are being observed in the various correlation techniques you have mentioned?

A. We haven't taken any actual data yet, so I can't answer that question, but I hope to be able to after we do the tests at the HYGAS pilot plant. We hope that fluctuations will be maintained for something like a few pipe diameters.

R. Chandrasekhar, Foster-Miller Associates

Q. Is ANL aware of a capacity type correlation meter developed at the Bradford University by Dr. M. S. Beck. We understand he is ready to commercialize this instrument for limited application.

A. I have recently become aware of it, and, of course, will look into it further.

Lee G. Dodge, United Technologies Research Center

Q. If fast time response instruments were available for gas analysis, how would this information be used in control of the process? What gases are most important for on-line analysis?

A. This questions is probably better referred to our process control panel on Friday, but in general the gases that are of most interest are the methane, carbon monoxide, hydrogen, CO_2, H_2O, H_2S, and SO_2.

D. D. Bruns, University of Tennessee

Q. Recognition that the two phases can have different velocities was clearly pointed out. In some measurements won't it be critical to account for the fact that each phase can have a velocity distribution across the flow field?

A. Yes, that will certainly be important, and this is one of the things that we'll have to investigate in this program.

Q. For example the velocity of particles would be strongly dependent on the particle size, position in the flow field, etc.

A. Yes, it's a very complicated process, and we've really just begun to scratch the surface. All of this will have to be considered.

Frank L. Cleary, Bituminous Coal Research

Q. What will be the temperature and pressure ranges of your calibration loop?

A. The one that we're building right now is just room temperature, atmospheric pressure. Eventually we would like to go up to 1700 or 1800°F for a char system. Pressure, we don't know yet. We'd rather not have to go to high pressure. Unless we can show that the pressure is going to make a difference in the measurement, we won't go to pressure, but if we have to, we will.

BI-GAS PILOT PLANT EXPERIENCE IN MASS FLOW MEASUREMENT

J. M. Miles
BI-GAS Pilot Plant
Phillips Petroleum Company
Homer City, Pennsylvania

BI-GAS PILOT PLANT EXPERIENCE IN MASS FLOW MEASUREMENT

John M. Miles
Phillips Petroleum Company

INTRODUCTION

The BI-GAS Pilot Plant is a "grass-roots" facility designed to study a new process for the conversion of coal into pipeline quality gas. A principle feature of the plant is a 2-stage entrained bed, high pressure (1500 psig max.), ash slagging and oxygen blown gasifier unit. The plant is located in Homer City, Pennsylvania and has been in operation for about one year. The BI-GAS program is funded by the U.S. Energy Research and Development Administration plus the American Gas Association under ERDA contract EF-77-C-01-1207.

The purpose of this paper is to describe the BI-GAS coal and char feed metering systems plus present a summary of our operating experience with these systems.

BI-GAS COAL + CHAR GASIFIER FEED SYSTEMS

Figure 1 illustrates the BI-GAS gasifier coal and char feed systems. Dried coal plus vaporized water and drying gas are fed to the coal cyclone vessel. A single cyclone is used to separate dried coal from the gaseous mixture. The gas is recycled to the coal drying area for reuse in the drying system. The coal cyclone vessel is operated at approximately 500 F and slightly greater than gasifier pressure. Coal is fed to the gasifier through two identical lines. Flow in each of the lines is metered as it leaves the coal cyclone vessel. Product gas and char from the gasifier are cooled from 1500-1700 F to 600-800 F by addition of liquid quench water. The quenched product stream is fed to the char cyclone system for separation of the char from product gas. Product gas goes to carbon monoxide shifting, Selexol gas treating and methanation processing. Char is accumulated in the char feed vessel at slightly less than gasifier pressure. Char flow is metered through three identical systems into the char reaction zone of the gasifier.

A more detailed portrayal of the coal feed system is shown in Figure 2. A nuclear level indicator on the coal feed vessel adjusts the flow control valve to obtain the desired flow. In addition, a "kicker" is used on the control valve to insure the movement of the V-port ball is continuous. Char flows through a four inch line containing an expansion joint, cut-off valve and flow meter before reaching the control valve. The flow meter is a thermal device described in the next section of this paper. A nuclear type density meter is also located on the coal feed line to indicate line pluggage or no-flow conditions in the lower section of the line.

Details of the char feed system are illustrated in Figure 3. This system is very similar to the coal feed system with the exception of three feed lines instead of two being used. When supplemental fuel is needed, fuel gas is added to the char feed as indicated in Figure 3.

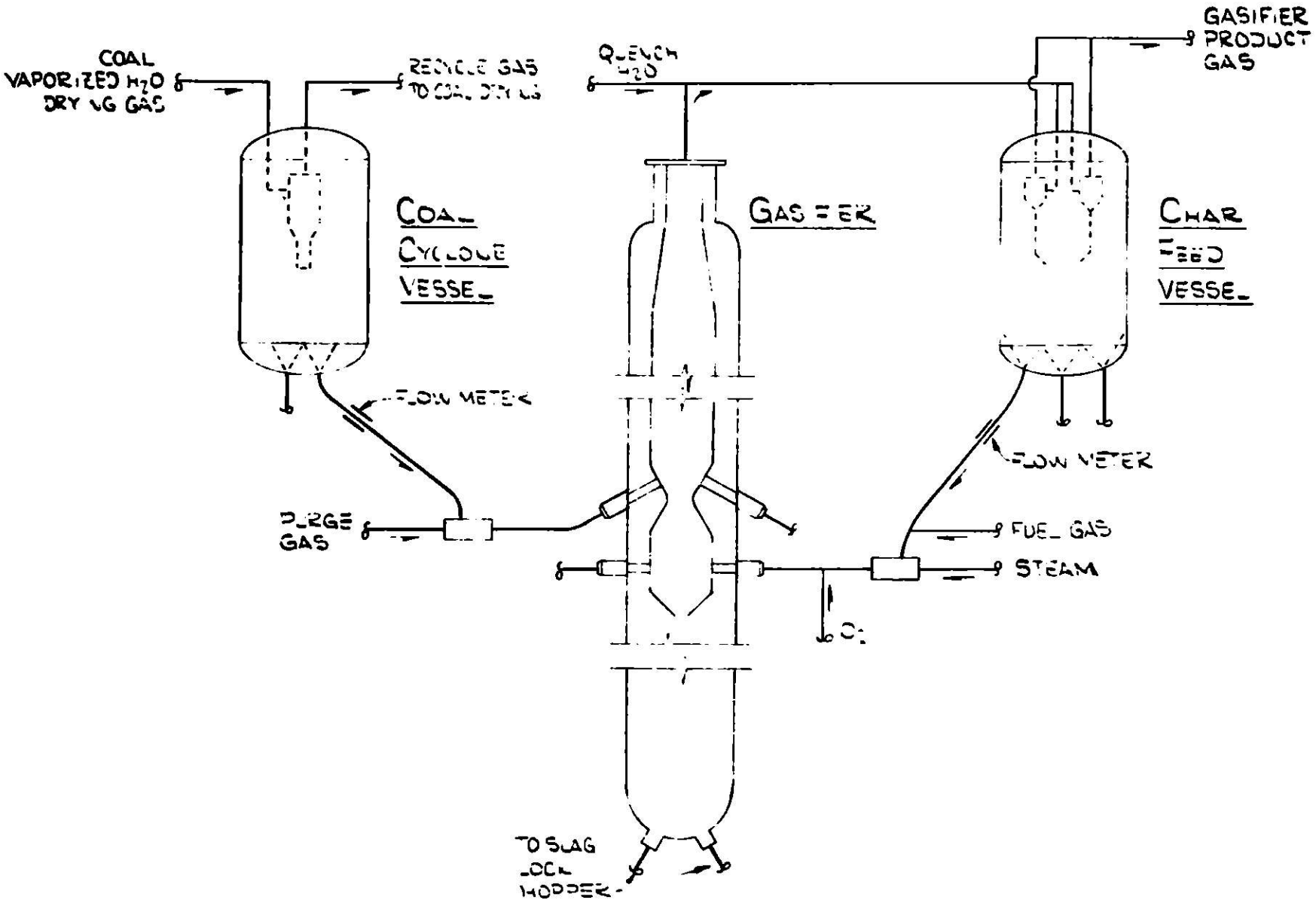

Fig. 1. BI-GAS Gasifier Coal and Char Feed Systems

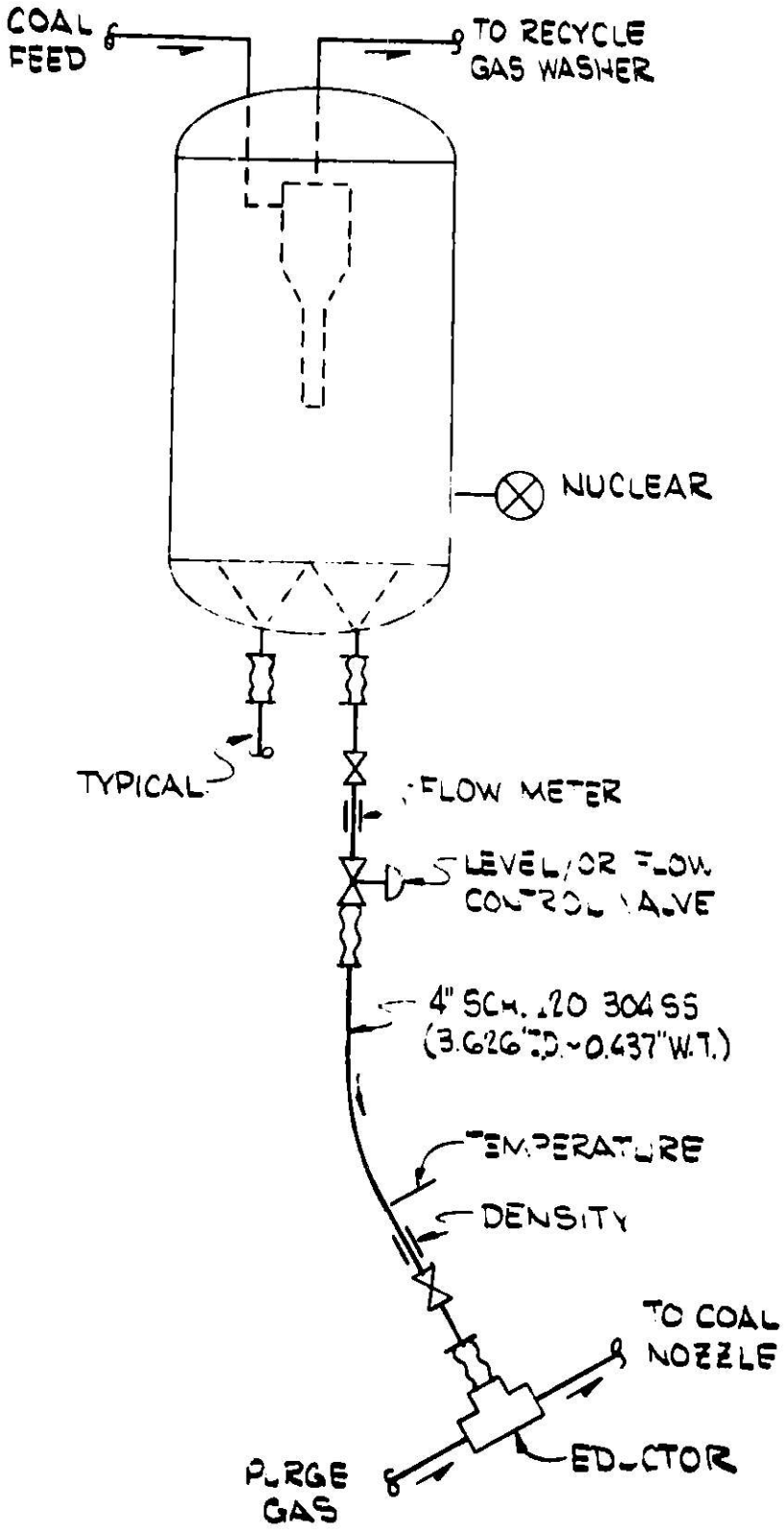

Fig. 2. Coal Feed System

THERMAL FLOW METER PRINCIPLE OF OPERATION

The Model 60 Thermal Flow Meter as supplied by Thermal Instrument Company is the flow measuring device used in each of the coal and char feed lines. Figure 4 presented a simplified sketch to illustrate the thermal flow meter operation. The flow meter is the same internal diameter as the feed line and presents an unobstructed flow area. Extremely accurate temperature sensors are located in the wall of the meter before and after an electrical heating device. The temperature sensors never directly contact the flowing material.

An upstream sensor measures temperature of the process stream. The downstream temperature sensor is maintained at a fixed temperature increment above the upstream temperature with an electrical power input. The voltage or power required to maintain the fixed temperature increment is proportional to mass flow rate.

Flow measurement with the thermal flow meter will be dependent on ambient temperature, process temperature and transport properties of the coal or char. The instrument contains automatic temperature compensation circuits but calibration at or near process conditions is required. There is no compensation for variations in transport properties of coal or char.

CALIBRATION OF COAL & CHAR FLOW METERS

Calibration tests of the coal and char meters were made with pulverized coal at ambient conditions. To obtain these calibrations, coal was charged to the coal and char feed tanks, dropped through the feed lines and collected in drums at the coal or char feed eductors.

Significant observations made during these initial calibration tests are listed in Table I. We are severly limited in our ability to properly calibrate the meters since we have no means of accurate calibration at process operating conditions. An indirect reading on coal flow can be obtained from a material balance around the coal drying system but we must depend on gasifier heat and material balance calculations to "back-into" char flow rates. This approach is currently being used to evaluate the effectiveness of the thermal flow meters at process conditions.

SUMMARY AND RECOMMENDATIONS

The BI-GAS thermal flow meters do show a response to solids flow through the coal and char feed lines. Additional testing at process conditions is needed to determine if the meters will provide reliable quantitative measurements.

An "off-line" system designed to circulate accurately measured quantities of solids at process conditions could greatly accelerate the development of meters to measure flows of high pressure, high temperature coal and char. The pilot plants are generally not "set-up" to provide this service. Several types of meters in addition to the thermal flow meter, have been suggested for accurate measurement of BI-GAS solids flow and the recommended solids circulation loop could be used to "screen" the suggested meter types plus provide calibration services for the pilot plants.

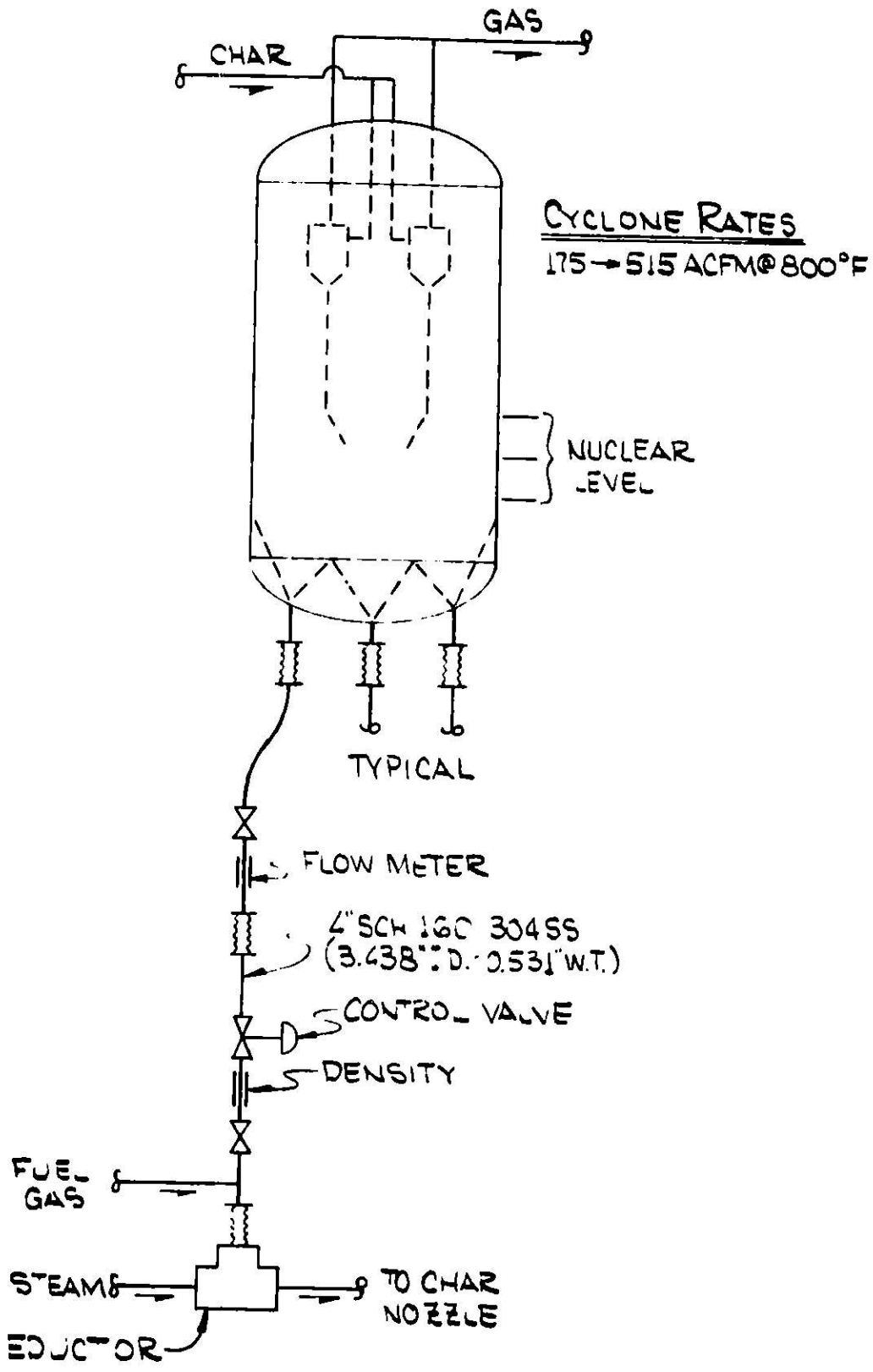

Fig. 3. Char Feed System

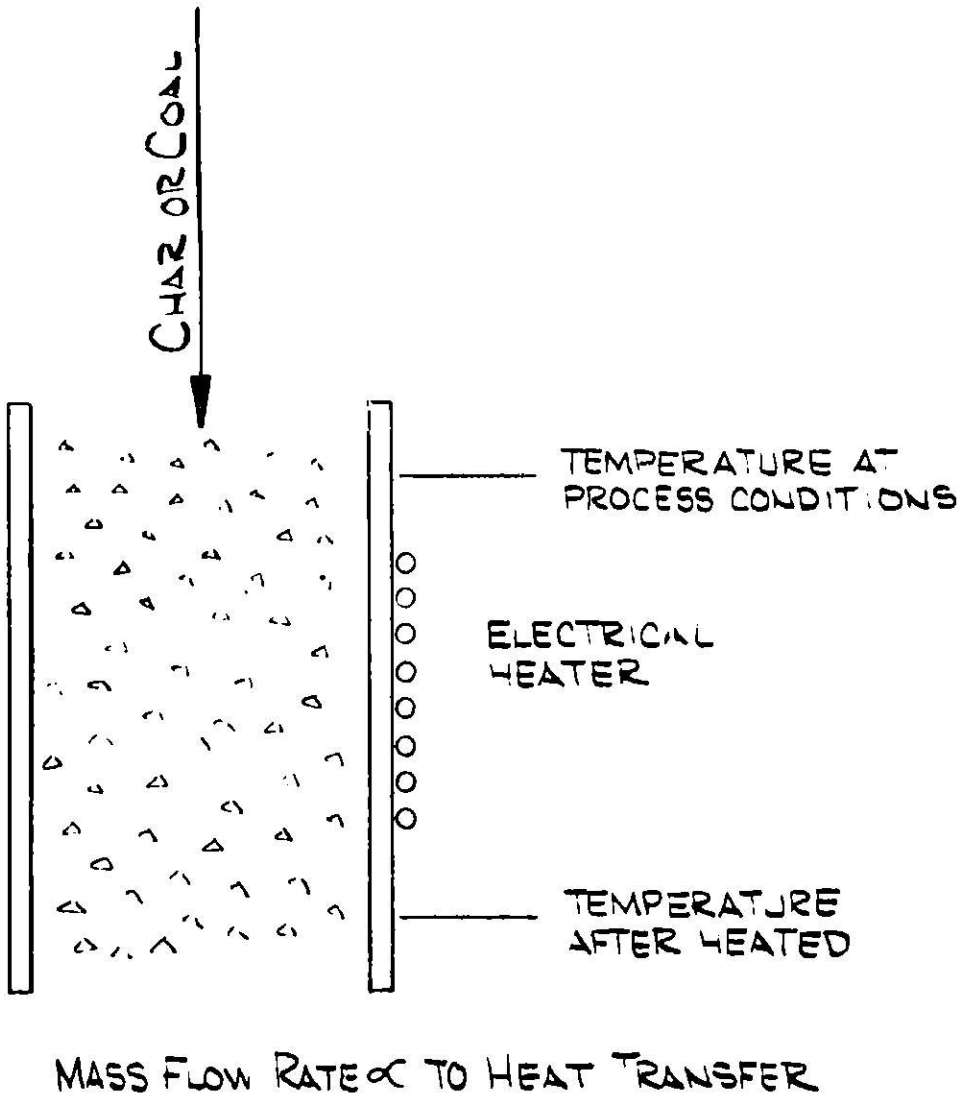

Fig. 4. Coal and Char Flow Meter Operation

TABLE I

OBSERVATIONS DURING INITIAL CALIBRATION STUDIES
OF BI-GAS THERMAL FLOW METERS

1. Temperature compensation for coal temperature was very sensitive over the small range of coal temperatures tested.

2. Approximately 30 minutes were required for the flow meter output to stabilize when changing from zero to a positive flow. After the first readings stabilized, subsequent changes in coal flow required 10 to 15 minutes for a stabilized reading.

3. Significant changes in ambient conditions (20 F° in 2 hours) appeared to effect the meter output.

4. Calibration curves for each meter are similarly shaped, but the magnitude of the outputs can vary significantly.

5. The meters responded to changes in flow rate. However, at flows greater than 1000 lbs/hr, the meters were less sensitive to changes in flow.

QUESTIONS AND ANSWERS

J. M. Miles

Phillips Petroleum Company

J. H. Vignos, The Foxboro Co.

Q. Have you looked to see what the temperature profile across the flowline is at the downstream temperature probe location?

A. No, we have not looked at that. One of the things that has concerned us about this meter, and you're touching on it here, is the fact that you do not get an integrated reading across the profile. That may have been what you were trying to point out, and that is of some concern to us. It seems that this would be a real weakness in this approach to making the measurement.

E. W. Lazor, Babcock & Wilcox Research Center

Q. Can you tell me what type of electric heater is used on the coal and char flow meter?

A. I am not really qualified to do that. Thermal Instruments literature does describe the electrical circuits in great detail. I have the literature available for your study after today's meeting.

S. H. Lee, Argonne National Laboratory

Q. What's the range of distance between two temperature sensors in the thermal flow meter?

A. I can give you approximate range. The total meter length is about 10 to 12 in. The distance between the sensors has to be something less than this.

A. T. Abromaitis, Bailey Meter Company

Q. How is the thermal flow meter affected by changes in the solids/gas ratio?

A. We have asked Thermal Instruments representatives this question and they say the reading will be affected very little. However, we do not have data to confirm this.

INSTRUMENTATION OF A WELLMAN-GALUSHA GASIFIER OPERATING ON ANTHRACITE FOR SYSTEM EVALUATION AND CONTROL

R. E. Maurer
Aerotherm Division of Acurex Corporation
Mountain View, California

INSTRUMENTATION OF A WELLMAN-GALUSHA GASIFIER OPERATING ON ANTHRACITE FOR SYSTEM EVALUATION AND CONTROL

R. E. Maurer
Project Engineer, Aerotherm Division of Acurex Corporation

R. W. Dammann
Vice President of Production, Glen-Gery Corporation

INTRODUCTION

The development of the industrial gas producer began in the early 1800's and continued actively for nearly 40 years under the direction of the Siemens Brothers in England. By the turn of the century, through the efforts of Ritter Von Kerpely of Austria (inventor of the first successful mechanical producer in Europe) and W. E. Hughes (inventor of the first successful mechanical producer in the United States), the gas producer was established as a reliable mechanical device. Its reliability, in fact, compared favorably with other mechanical equipment in the plants where it was used.

The conversion efficiency of these early units was nominally 90 percent when the sensible heat of the gas was utilized. When the sensible heat was lost (due to transportation heat losses or gas scrubbing) the conversion efficiency dropped to about 80 percent and when the losses of operating the scrubbing equipment were considered, the net efficiency of scrubbed gas was generally closer to 70 percent. For that reason about 95 percent of all producer-gas installations in the 20's through 40's used hot raw gas to take advantage of the higher efficiency.

During this era, industrial gas producers -- like Wellman-Galusha, Chapman, Morgan, and Wood -- flourished. In the fifties, however, the pipeline system was developed to supply relatively inexpensive and clean natural gas, and the gas producers were displaced as an industrial fuel supply. Today there are less than five active users of producer gas in the United States.

As supplies of natural gas dwindle, however, the industrial gasifier is being recognized as a viable means of supplying alternate industrial fuel. Yet, in spite of the fact that these gasifiers have been used in industry for many years, few quantitative data relating to their operation and performance are available. Part of the reason of this is the current method of assessing gasifier performance by probing the bed manually with metal rods through poke holes in the top of the reactor. This procedure is not only dangerous, but provides only qualitative results.

As part of its effect to demonstrate the use of alternate industrial fuels, the United States Energy Research and Development Administration is funding a research program to assess gasifier performance, and integration with industrial processes. The program is being conducted on a cost-shared basis by Aerotherm Division of Acurex Corporation and Glen-Gery Corporation, one of the few remaining users of producer gas in the United States. Since the early fifties, Glen-Gery has used producer gas to supplement the natural

gas and fuel oil burned in their tunnel kilns. The low Btu gas is produced in Wellman-Galusha gasifiers from locally mined anthracite. The Acurex/Glen-Gery program will install, instrument, monitor, control, and assess the operational performance of a Wellman-Galusha gasifier at Glen-Gery's York, PA plant.

This paper (1) reviews the operation of a Wellman-Galusha gasifier, (2) establishes the objectives of the ERDA program to instrument and monitor a gasifier for 12 months, (3) identifies the measurement requirements, range of variables, and measurement locations, and (4) describes the instrumentation techniques selected or to be developed to acquire the desired operational data.

Wellman-Galusha Gasifier Operation

A schematic of the Wellman-Galusha gas producer is shown in Figure 1. The height of the unit from the floor to the top of the coal elevator is nominally 70 feet. Coal is transported from the storage pile (at ground level) to the upper storage bin via a coal elevator. Approximately 25 tons of coal can be stored in a 10-foot diameter gasifier. Under peak operating conditions, anthracite is used at about 1 ton/hour. Coal feeds into the reactor bed by gravity. A lock hopper, located between the upper storage bin and the coal feed pipes, assures uninterrupted coal flow into the reactor without loss of producer gas.

Ash is continuously removed from the bottom of the reactor vessel by a slowly revolving grate which makes about one revolution per hour. The grate is constructed of circular heavy steel plates, as shown in Figure 2. Each plate is flat and solid, and is set one above the other with overlapping edges so that ash is removed by passing horizontally through the vertical space between the plates. The ash drops onto the eccentrically stacked plates and is pushed between them as the grate rotates.

The reactor vessel is completely water-jacketed, the inner wall being constructed of 1-inch thick steel plate. This maintains an inner steel surface temperature below 300°F. This design eliminates the requirements for brick lining and the corresponding maintenance and operational problems associated with brick linings (e.g. clinker buildup on the inner surface and liner replacement).

The hot water in the jacket (~180°F) generates the steam required to produce the gas. A blower supplies air to the reactor bed, the air passing over the steaming water at the top of the reactor, picking up both heat and water vapor. The saturated air then enters the reactor bed by passing from below the grate up through the ash zone and primary reaction zone. Air saturation is automatically controlled by the water jacket temperature (e.g., by controlling the water flow through the jacket). Water flow through the jacket is controlled by a thermostat which measures the air wet bulb temperature as it enters the reactor below the grate.

Wellman-Galusha gas producers operating on anthracite generally do not need agitators within the bed. Agitators are required to maintain bed

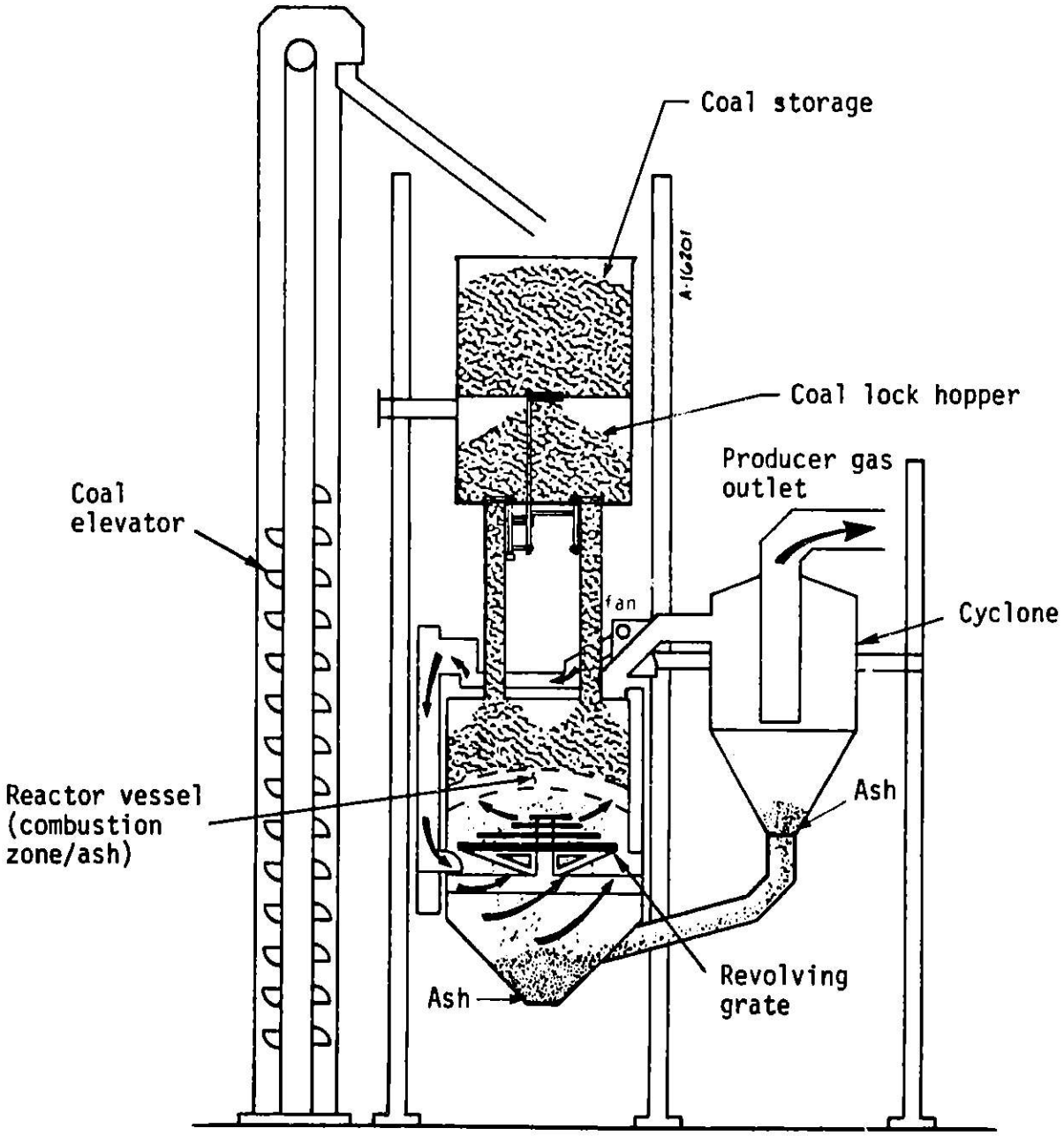

Figure 1. Wellman-Galusha gasifier.

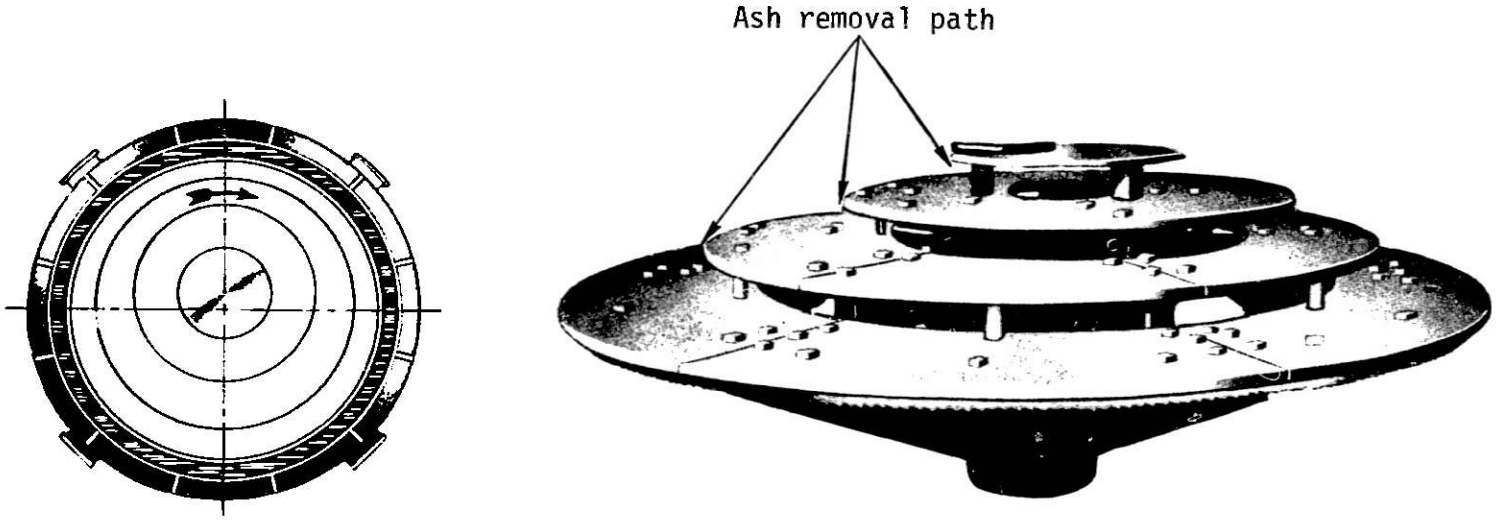

Figure 2. Wellman-Galusha — revolving grate design.

uniformity when gasifying a bituminous coal which may swell and cake during devolitization. The agitator is a slowly revolving horizontal arm which spirals vertically within the coal in the reactor. This stirring of the bed retards channeling by maintaining bed uniformity. The main body and arms of the agitator are water-cooled, and the wearing surfaces are protected by heat- and wear-resistant castings. The agitator is not shown in Figure 1, since the gasifier being monitored on this program does not contain an agitator.

The producer gas exits at the top of the reactor vessel and directly enters a cyclone for removal of particulate. When gasifying anthracite, the producer gas off take temperature is generally between 500 to 600°F. The cyclone is thermally insulated with an inner lining of fire brick. Particulate collected in the cyclone contains both ash and carbon. The cyclone collects about 200 to 300 lbs of particulate daily.

The reactor bed is monitored by poking steel rods into the bed from the top of the vessel. A total of 12 poke holes are available (9 located circumferentially around the perimeter of the vessel with three arranged near the center of the vessel). The rods are manually driven into the bed by operators once or twice during each 8-hour shift. The rods are left in the bed for about 5 minutes. When removed, the operator notes the different thermal zones on the poke rod, and from this can determine (1) the height of the ash zone and (2) the height of the reaction zone. By probing the entire bed in this manner, the operator evaluates bed uniformity and ash zone height, both critical parameters for high quality gas production. The operator controls the gasifier performance principally by (1) grate rotational speed (e.g. rate of ash removal) (2) air wet bulb temperature entering the gasifier and (3) size and quality of the coal.

Most problems in a firebed begin with the development of chimneys or high temperature stream lines. If allowed to continue, they develop into blowholes. Once blowholes exist, the gas quality is lowered and clinkers are often formed. Hot spots in a gas producer are generally caused by a lack of uniformity in one or more of the following operations: (1) feeding and spreading the fuel, (2) agitating the entire firebed (for swelling and caking coals), and (3) ash removal. For the Wellman-Galusha gasifier operating on anthracite coal ash removal and the corresponding uniformity of the ash zone is the most critical operational parameter for consistent high quality gas production. This program will pursue developing a more automated means of monitoring both the ash and reaction zones with the reactor. Several instrumentation concepts being studied are reviewed subsequently.

Ash removal occurs automatically via the revolving grate. Ash is collected in the ash hopper directly below the reactor. The ash hopper is generally emptied once a day by dumping the ash into a truck driven under the gasifier. Most anthracite yields about 3 tons of ash daily (e.g. 12- to 13-percent ash).

ERDA Program Objectives

The program objectives are to evaluate the Wellman-Galusha gasifier (1) technically, (2) economically, (3) environmentally and (4) operationally.

Initially the technical evaluation will focus on measuring the gasifier's baseline operation. This will require computing detailed gasifier mass and energy balances. Once the baseline operation is measured and evaluated, operational studies will be performed to establish the system's peak thermal efficiency. After the system's peak operating conditions have been established, the economic evaluation will proceed. The economic considerations are (1) total gasifier system efficiency and (2) producer gas cost per Btu.

Environmental measurements are required to establish the effects of the gasification process and producer gas on the external plant environment. This phase of the program will focus on evaluating the environmental impact of the ash and kiln stack effluents.

Monitors for operational safety and control are required to enhance personnel safety and to ease the operation of the gasifier unit. Under current operating conditions the fugitive emissions (producer gas) from the Wellman-Galusha gasifier can be significant. The relatively high concentration of CO in the producer gas presents potential hazards. Thus, there is a strong desire on the part of Glen-Gery personnel to enclose or seal the gasifiers as effectively as possible. This implies several requirements regarding additional monitoring instruments to acquire operational data currently obtained manually.

Further details regarding measurement requirements for the technical evaluation and the approximate locations of the instrumentation are presented in the next section.

Required Gasifier Measurements

This section describes the measurements to be made directly on the gasifier required to establish the systems mass and energy balances. The inlet and outlet streams in a Wellman-Galusha gasifier are shown schematically in Figure 3. Inlet streams consist of (1) coal, (2) air, and (3) water into the gasifier water jacket. Outlet streams consist of (1) producer gas, (2) ash, and (3) water from the gasifier water jacket. The difference between the inlet and outlet water flowrates corresponds to the water uptake of the air. The air enters the gasifier at ambient conditions, wherein it flows over the hot water (~180°F) in the water jacket. The air is heated and humidified (i.e., to saturation) prior to entering the gasifier reaction bed. The air "wet bulb" temperature entering the gasifier bed under baseline conditions is in the range of 130 to 145°F.

An approximate gasifier mass balance was made, based on the coal ultimate analysis and the producer gas composition provided by Glen-Gery (Reference 1). Table 1 summarizes the coal ultimate analysis on a dry, ash

free basis and an approximate producer gas composition (dry basis). Assumptions made to complete the mass balance include:

1. No carbon is contained in ash
2. Producer gas contains no water
3. Coal contains no water (all steam into the gasifier is derived from the water jacket)
4. Ash content of coal is 12.5 percent
5. The thermal efficiency of the gasifier is 85 percent

TABLE 1. DATA USED FOR PRELIMINARY GASIFIER SYSTEM MASS BALANCE[a]

Coal Ultimate Analysis (Dry, Ash Free)		Producer Gas Composition (Dry)	
Element	Mass Fraction	Species	Mole Fraction
C	0.935	CO	0.260
H	0.026	H_2	0.120
O	0.023	CH_4	0.005
S	0.007	CO_2	0.060
N	0.009	N_2	0.555
	1.000		1.000
Btu content = 12,700 $\frac{Btu}{lb}$		Btu content = 130 $\frac{Btu}{scf}$	

[a]Personal communication with R. W. Dammann, Glen-Gery Corporation November 22, 1976.

Figure 3 summarizes the resultant mass balance, based on an assumed input of 2000 lbs of coal. This mass balance is preliminary, due to the approximate producer gas analysis and the lack of quantitative measurement of inlet and outlet flowrates.

The energy balance is readily established from the mass balance by measuring the energy content of all inlet and outlet streams. This involves measuring the temperature of inlet or outlet streams such as coal, air, water, and producer gas. The measurements required to perform a complete gasifier mass and energy balance are listed in Table 2.

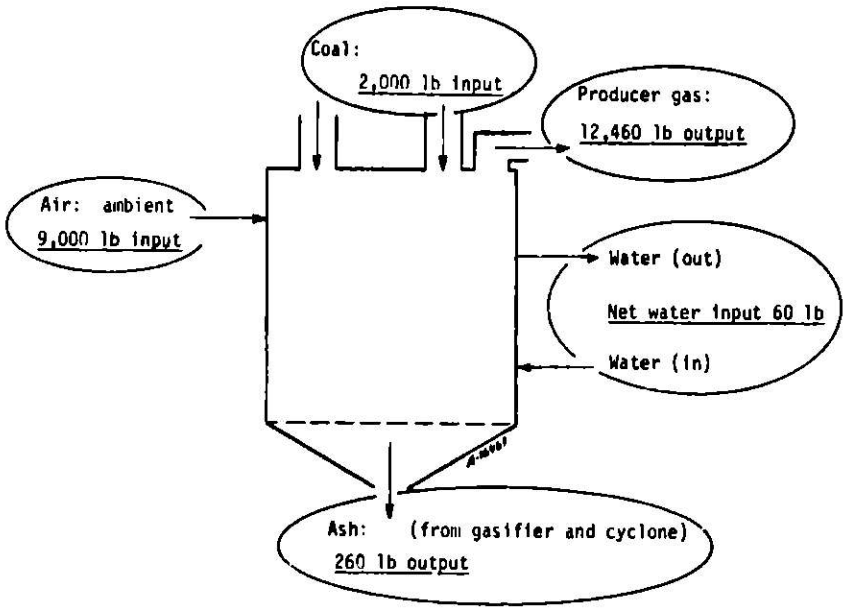

Figure 3. Approximate mass balance of Wellman-Galusha gasifier operating on anthracite.

These measurements will be made for several months to establish the uncertainty in each measurement under baseline operation. Once a statistically significant data base is established, detailed mass and energy balances will be calculated. Once the gasifier's baseline thermal efficiency has been established and rationalized with expected values a matrix of operating variables will be established. The purpose of this matrix of operational variables will be to establish the gasifier's peak thermal efficiency. The operational variables to be included in the matrix include:

1. Water flowrate (steam input)
2. Grate rotational speed (ash outlet flow)
3. Air flowrate
4. Coal size
5. Coal additives (to enhance carbon utilization)

The water flowrate into the water jacket controls the water jacket temperature which in turn controls the air saturation temperature entering the gasifier. A reduced water flowrate results in a higher water jacket temperature and a higher air saturation temperature (i.e., a higher steam content). A higher inlet air "wet bulb" temperature will reduce the gasifier reaction bed temperature and the gasification reaction rates due to the increased steam content of the air.

The grate rotational speed controls the rate of ash removal from the gasifier. The principal purpose of the ash is insulation of the

TABLE 2. MEASUREMENT REQUIREMENTS FOR GASIFIER MASS AND ENERGY BALANCE

Input Streams	Measurement Frequency
Coal	
Mass Usage Rate ~1 T/Hr	Daily average[a]
Elemental Composition (Ultimate Analysis)	Once a Week
Btu Content (Ultimate Analysis)	Once a Week
Air	
Inlet Flowrate ~9240 lb/hr (dry)	Continuous
Temperature, Ambient	Continuous
Relative Humidity	
Wet Bulb Temperature Upon Entering Gasifier 140°F	Continuous
Pressure Upon Entering Gasifier Bed	Continuous
Water	
Flowrate	Continuous
Temperature ~70°F	Continuous
Output Streams	**Measurement Frequency**
Producer Gas	
Flowrate ~12460 lb/hr (dry)	Continuous
Temperature ~550°F	Continuous
Pressure ~15.5 psia	Continuous
Composition	Continuous
Btu Content	Continuous
Ash	
Mass Flowrate (Gasifier and Cyclone)	Once a Day
Carbon Content	Once a Week
Water	
Flowrate	Continuous
Temperature ~180°F	Continuous

[a]By calibration of coal elevator.

mild steel grate and a filtration/distribution effect of providing an even airflow through the bed. An optimum balance is required between the ash depth and grate rotational speed to insure proper insulation. The ash depth is currently monitored by "poking" the gasifier bed with steel rods. This is a manual process which is difficult, hazardous, and only qualitative. To improve the thermal monitoring of the bed, several fixed, water cooled probes with thermocouples at various depths may be located within the bed to provide a continuous monitor of the ash depth and primary reaction zone.

The air flowrate directly controls the rate of gasification and size of the reaction zone. Empirically established limits on the air flowrate have been established through years of operating the gasifiers at Glen-Gery Corporation. The purpose of varying the airflow on this program is to quantify the dependence of producer gas quality (Btu content) and production rate with airflow.

Coal size is an important operational variable. Currently, the gasifiers are operated with anthracite in the size range of Buckweat #2 and Pea (i.e., 5/16 inch to 13/16 inch coal). As the coal size increases the throughput increases, in fact the bed is routinely "cleaned" by using the larger Pea sized coal. Airflow is increased (pressure drop decreased) as the coal size increases, thus the larger coal burns hotter and faster. It will be desirable to evaluate the process efficiency and throughput variations with anthracite size.

The ash carbon content is important from the standpoint of the systems thermal efficiency. The ash carbon content has never been routinely measured at Glen-Gery, thus no useful data are currently available. If the ash carbon content is found to be excessively high (i.e., greater than 10 percent) there are coal additives available which enable the gasification reactions to proceed to completion. Such additives will be evaluated if the need exists to reduce the ash carbon content.

The gasifier's peak thermal efficiency and the corresponding operating conditions will be established by varying the above independent variables. The measurements previously specified in this section will enable the system operator to monitor and maintain the gasifier at its peak thermal efficiency.

The measurement and monitoring requirements identified for the technical evaluation are delineated in Table 3 and shown on the schematic in Figure 4. Instrumentation selections and reactor bed probe designs are discussed in the next section.

TABLE 3. TABULATION OF GASIFIER PROCESS MEASUREMENTS

Stream	Location	Quantity	Range	Frequency
Inlet:	(Q 1)			
Coal	(A 1) Sample collected at elevator base	Measure coal composition of anthracite (ultimate analysis and Btu content)	NA	Weekly
	(WT 170) Coal elevator	Measure coal mass into gasifier (via calibration of coal elevator)	~1 T/hr	Daily
	(TE 116) Above upper coal bin	Ambient temperature (fire safety)	20 to 500°F	Continuous
Air	(AE 201) Air inlet duct	Measure relative humidity of air entering gasifier	ambient (0 - 100%)	Continuous
	(FE 132) Air inlet duct	Measure inlet flowrate into gasifier	~5 $\frac{\text{lb.air}}{\text{lb.coal}}$	Continuous
	(TE 113) Air inlet duct	Measure air entering gasifier	0° to 120°F	Continuous
Water	(A 4) Water line downstream from softener	Measure Ca content in water	NA	Daily
	(FE 131) Inlet water line	Measure water flow into water jacket	to be specified	Continuous
	(TE 111) Inlet water line	Measure water temperature entering the water jacket	~70°F	Continuous
Gasifier Bed Measurements:	(AE 202) In vicinity of air entry to reaction zone	Measure relative humidity of air entering gasifier reaction zone	~100% (wet bulb)	Continuous
	(DPT 141) In vicinity of air entry to reaction zone	Measure air pressure just below reaction zone	15 – 30 psia	Continuous
	(TE 115) In vicinity of air entry to reaction zone	Measure air temperature entering gasifier	(110 - 180°F) (wet bulb)	Continuous

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TABLE 3. Continued

Stream	Location	Quantity	Range	Frequency
	(PT 142) Producer gas exit duct (upstream of cyclone)	Measure producer gas pressure	(14. - 16 psia)	Continuous
	(TE 114) Producer gas exit duct (upstream of cyclone)	Measure producer gas temperature	(600 - 1000°F)	Continuous
	(TE 321) [a] Within the gasifier bed (down to the grate)	Measure the bed temperature distribution in primary reaction zone	up to 3000°F	Continuous
Outlet:				
Ash (gasifier)	(Q 2) Gasifier ash bin	Measure ash mass from gasifier hopper	~3T/day	Daily
	(A 2) Gasifier ash bin	Measure ash carbon content	NA	Monthly
Ash (cyclone)	(Q 3) Cyclone ash bin	Measure ash mass from cyclone	~200 lb/day	Daily
	(A 3) Cyclone ash bin	Measure ash carbon content	NA	Monthly
Producer Gas	(DPT 203) Cyclone	Measure pressure drop across cyclone	~1 - 10" wg	Continuous
	(AE 203) Producer gas line (downstream of cyclone)	Measure producer gas H_2O content	~10%	Continuous
	(AE 233) Producer gas line (downstream of cyclone)	Measure producer gas CH_4 content	~0.5%	Continuous
	(AE 232) Producer gas line (downstream of cyclone)	Measure producer gas CO_2 content	~6%	Continuous
	(AE 231) Producer gas line (downstream of cyclone)	Measure producer gas CO content	~26%	Continuous
	(AE 211) Producer gas line (downstream of cyclone)	Measure producer gas O_2 content	<4%	Continuous

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[a] Gasifier temperature probes — probe design currently under development

TABLE 3. Concluded

Stream	Location	Quantity	Range	Frequency
	(AE 234) Producer gas line (downstream of cyclone)	Measure producer gas Btu content	130 - 160 $\frac{Btu}{scf}$	Continuous
	(FE 133) Producer gas line (downstream of cyclone)	Measure producer gas flowrate	~6 $\frac{lb.gas}{lb.coal}$ @ 600°F	Continuous
Water	(TE 112) Water outlet line	Measure outlet temperature	150 - 200°F	Continuous
	(FE 170) Water outlet line	Measure water outlet flowrate	to be specified	Continuous
Fugitive CO[b] Emissions	(AE 221) In vicinity of upper coal bin	Measure ambient CO concentration	NA	Continuous
	(AE 222) In vicinity of operators station	Measure ambient CO concentration	NA	Continuous
	(AE 223) In vicinity of brick kiln burners	Measure ambient CO concentration	NA	Continuous

[b]Measurement for operational safety

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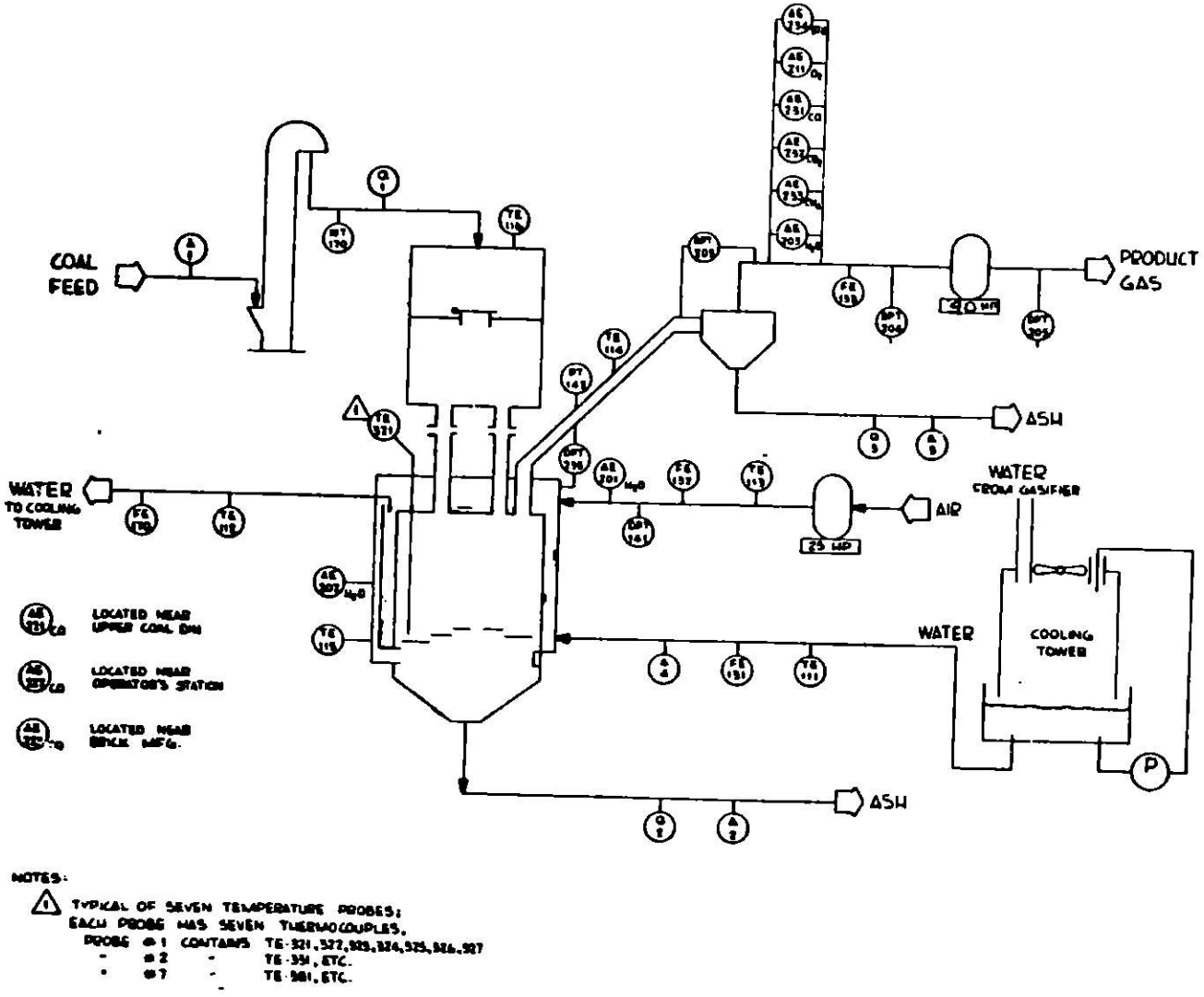

Figure 4. Schematic of measurement locations on the Wellman-Galusha gasifier.

Instrumentation Selection and Development

This section describes several of the major instrumentation systems to be applied to the Wellman-Galusha gasisifer at Glen-Gery's York, PA plant. Table 5 lists all of the instrumentation systems. The measurement I.D. numbers correspond to the list of measurements in Table 4 and the gasifier schematic ir Figure 4. The following discussion is keyed to that list and briefly describes the instrumentation systems selected for application.

Flow measurement FE-131 and 170 are of water flow in and out of the producer water jacket. The most commonly used industrial flowmeter in the 5 to 10 gpm range is the Niagra Doppler model DTS-2 flowmeter. Equipped with pulse totalizing and conversion circuitry it will produce instantaneous flowrates and total integrated flow information.

Gas flow measurements in general are handled by a combination of an Ellison-detrich Co. Annubar multiported pitot tube and a Validyne P207-1 differential pressure transducer. The close coupling between the gas producers, and the distribution valving and piping makes it impossible to obtain the required 8 to 10 duct diameters required up and downstream of classic surface or venturi flowmeters. Thus, using these techniques could lead to a 10- to 30-percent error in flow measurement. The Annubar sensor is designed specifically to operate best in skewed flow environments were ordinary techniques are inadequate.

The Validyne P207-1 differential pressure transducer is used for flow measurements and normal differential pressure measurements. Since the pressures wihin the producer system are below 1 psig, all pressure measurements will be made as differential measurements from atmospheric for increased accuracy. There are many differential pressure transmitters available on the industrial market. The Validyne P207-1 is a relatively new version of a high accuracy variable reluctance transducer. The Validyne Units are used for FE-132, FE-133, FE-400, DPT-141, 142, 203, 204, 205, and 402.

The moisture content of several of the gas streams must be known for mass and energy balances. Dew points are measured using the General Eastern Model 1200 Condensation Dew Point Hygrometers. The technique is directly measuring the temperature of a mirror when a film of water vapor begins to condense and reduce its reflectance. The dew point is a fundamental psychrometric measurement wnich can be directly converted to percent water vapor. This technique is not affected by H_2S, S, H_2, or CO as some of the other chemical and physical techniques such as salt conductivity, etc. Since it is all electronic and solid-state, the mirror condensation technique should be more trouble free than the wet bulb/dry bulb with its water supply. Dew points are measured at the air inlet (AE-201), the water jacket air exit (AE-202), and the producer gas outlet (AE-203). The producer gas is filtered prior to passage through the hygrometer.

The oxygen content of the producer gas is one of the primary operating variables in terms of operator safety. The safety of the operation depends on an even distribution of air/water flow within the fire zone and the

complete combustion of all oxygen in the air. Too little oxygen supply will lower producer gas output while more than 3- to 4-percent oxygen in the producer gas may lead to after burning or even an explosion. An online oxygen analyzer will be used at the product gas outlet.

A Teledyne 327 (semiexplosion proof) analyzer was selected for this measurement on the basis of wide operating usage in various combustion environments. Other O_2 monitors operating on a similar fuel cell principal or the paramagnetic or thermomagnetic principal would be equally suitable. The only common type of O_2 analyzer which is not felt to be suitable is the heated zinconium oxide cell which could act as an ignition source above 1200°F.

The Btu content of the producer gas is a major operating parameter. Sigma Instruments and Cutter-Hammer are the primary producers of gas calorimeters in the U.S. The COSA unit by Sigma (AD1-203) is designed for low-pressure sources, and thus is more suitable for the Wellman-Galusha producer.

In order to warn the operator of potentially hazardous ambient carbon monoxide buildups, we are locating three Mini Safety Appliance Model 701 monitors in the vicinity of the various operating stations (AE-221 to 223). One monitor will be above the coal hopper, one at the producer operation level and one near the kiln area. Since Glen-Gery already uses MSA 701's, we have selected this model for CO safety monitoring.

Part of the chemical composition of the producer gas is measured by three nondispersive infrared analyzers measuring carbon monoxide, carbon dioxide and methane. With these three measurements, the Btu content and the total producer gas and airflows, it is possible to calculate the hydrogen and nitrogen contents. Nondispersive infrared analysis was selected over gas chromatography or mass spectroscopy as providing better online reliability and reduced operator requirements.

The remaining measurements within the producer are temperatures at many locations. Temperatures in various locations in the facility will be measured with platinum resistance thermometers (RTD's) in the temperature range below 1000°F type K thermocouples from 1000°F to 2200°F, and types R platinum thermocouple to 2700°F. The location and type of thermocouple or RTD is indicated in Table 4.

In addition, laboratory measurements will be made on samples of coal, water, and ash takes at various times. These analyses will be made by a commercial laboratory. For example, coal and ash will be analyzed for carbon content to close a carbon mass balance to determine efficiency. The ash will be analyzed for trace metals, plus soluble and insoluble compounds for environmental information. Water will be analyzed for hardness, etc. to check the efficiency of the water treatment units.

Instrumented Reactor Bed Probe Development

Instrumentation concepts to continuously monitor the gasifier reactor bed will be researched on this program. Two conceptual designs of

TABLE 4. INSTRUMENT LIST FOR MONITORING A WELLMAN-GALUSHA GASIFIER

Measurement I.D. Number	Online	Suggested Supplier	Range	Description
FE-131	Yes	Barton	2-5 gpm	Water flowrate into/out of cooling jacket
FE-170	Yes	Barton		
FE-132	Yes	Annubar		Air flow into gasifier
FE-133	Yes	Annubar		Producer gas flow
DPT-141	Yes	Validyne P132	0-6" wg	Air into reaction zone
DPT-142	Yes	Validyne P132	0-6" wg	ΔP across producer outlet
DPT-203	Yes	Validyne P132	0-6" wg	ΔP across cyclone
DPT-204	Yes	Validyne P132	0-6" wg	Producer gas into blower
DPT-205	Yes	Validyne P132	0-2" wg	Producer gas into blower
AE-201	Yes	General Eastern 1211 BP/1201	60-150°F	Air inlte (dew point)
AE-211	Yes	Teledyne 326A	0-5, 25%	O_2 producer gas
AE-202	Yes	General Eastern 1211 BP	60-150°F	Humidified air into run zone
AE-203		1201	60-150°F	Dew point of producer gas
AE-215	Yes	MSA 701	500 ppm	CO monitor
		MSA 701	500 ppm	CO monitor
		MSA 701	500 ppm	CO monitor
AE-231	Yes	Beckman 864-13-2-3-10	0-30%	CO monitor (NDIR)
AE-232	Yes	Beckman 864-23-2-3-10	0-10%	CO_2 analyzer (NDIR)
AE-233	Yes	Beckman 864-31-2-3-10	0-2%	CH_4 analyzier (NDIR)
Q-1	No	N/A		Mass of coal into gasifier
Q-2	No	N/A		Mass of ash from gasifier
Q-3	No	N/A		Mass of ash from cyclone
A-1	No	N/A		Lab analysis of coal
A-2	No	N/A		Lab analysis of ash from gasifier
A-3	No	N/A		Lab analysis of ash from cyclone
A-4	No	N/A		Lab analysis of water
TE-111	Yes	RTD	32-100°F	Inlet water temperature
TE-112	Yes	RTD	32-212°F	Outlet water temperature
TE-113	Yes	RTD	0-150°F	Inlet air temperature
TE-114	Yes	K T/C	400-1200°F	Producer gas temperature
TE-115	Yes	RTD	32-212°F	Water jacket temperature
TE-116	Yes	K T/C	32-1400°F	Coal bin temperatures

TABLE 4. Concluded

Measurement I.D. Number	Online	Suggested Supplier	Range	Description
TE-121 thru TE-127	Yes	by Acurex	32-2700°F[a]	Bed temperature distribution
TE-131 thru TE-137	Yes	by Acurex	32-2700°F[a]	Bed temperature distribution
TE-141 thru TE-147	Yes	by Acurex	32-2700°F[a]	Bed temperature distribution
TE-151 thru TE-157	Yes	by Acurex	32-2700°F[a]	Bed temperature distribution
TE-161 thru TE-167	Yes	by Acurex	32-2700°F[a]	Bed temperature distribution
TE-171 thru TE-177	Yes	by Acurex	32-2700°F[a]	Bed temperature distribution
TE- 81 thru	Yes	by Acurex	32-2700°F[a]	Bed temperature distribution

[a]Use R T/C; 32-2700°F

T-429

continuously recording reactor bed probes are shown in Figures 5 and 6. The instrumented vertical probes shown in Figure 5 is an extension of the poke rods currently used. The probes would be permanently attached to the upper surface of the gasifier and extend through the bed into the ash zone. The type of bed temperature data desired will dictate whether the probes are water cooled.

Water cooled probes would provide only qualitative temperature data because the fingers protruding into the bed would be required to remain below 1600°F. The probe would be constructed of high temperature stainless steel or a superalloy (e.g. 310 stainless or Incol 800). Actively cooled bed probes such as these would provide thermal data which would indicate ash zone/reaction zone interface and the extent of the reaction zone, but would not provide quantitative bed temperatures. This would provide an automated and continuous reactor bed monitoring extension of the current hand poking technique.

Uncooled probes would necessarily be constructed of a refractory ceramic (e.g. high density alumina -- Castolast "G"). These fixtures would be custom molded to the required length and geometry. The fingers on the uncooled probes would be positioned at 2- to 4-inch intervals around the circumference of the shaft to provide the ±2-inch resolution desired in controlling the ash zone level. The nominal ash zone depth in a Wellman-Galusha gasifier is 10 to 12 inches under operation with anthracite.

An alternative bed probe design is illustrated in Figures 6 and 7. With this design the instrumented fingers protrude from the inner surface of the reactor vessel. The finger protruding into the bed wouldn't be actively cooled because the attachment housing is integral to the cool water jacket. The external portion of the housing would be attached to the outer shell of the water jacket via bellows to afford any differential expansion between the inner and outer shells. A reactor bed thermocouple probe of this design is desirable because of its simplicity (i.e. no active cooling required) plus it enables various materials and probe geometries to be evaluated. Sidewall probes such as these could be removed and replaced with other probe hardware while the gasifier is online.

The response of probe materials and the effect of permanent probes on the performance of the gasifier can only be achieved by online evaluations. Such studies will be initiated on this program.

Data Acquisition and Recording

A schematic describing the data acquisition system is shown in Figure 8. The data channels from both the gasifier and kiln instrumentation modules initially interface with an Autodata Nine which provides A/D conversion and simple data sorting and evaluation. The data then enter a Modcomp II computer which has the following capabilities:

(1) Data storage on tapes (for subsequent analyses)

(2) Data storage on discs

(3) Summary report generation

(4) CRT display for operator interragation

Subsequent analyses can be performed at any site through use of the data tapes. complete data analyses are currently planned to be performed at Acurex's home office in Mountain View, California.

Summary

This ERDA program will establish on a timely basis the operational details of a 10-foot diameter Wellman-Galusha gasifier supplying fuel for an industrial brick kiln. Instrumentation techniques will be developed, tried, and evaluated. The measurement techniques and operational data will enable both ERDA and Glen-Gery Corporation to accurately evaluate the efficiency of anthracite gasification. Data from this program will enable the government (via ERDA) to evaluate and promote low-Btu producer gas from anthracite as an alternate fuel for other industrial processes throughout the northeastern part of the United States.

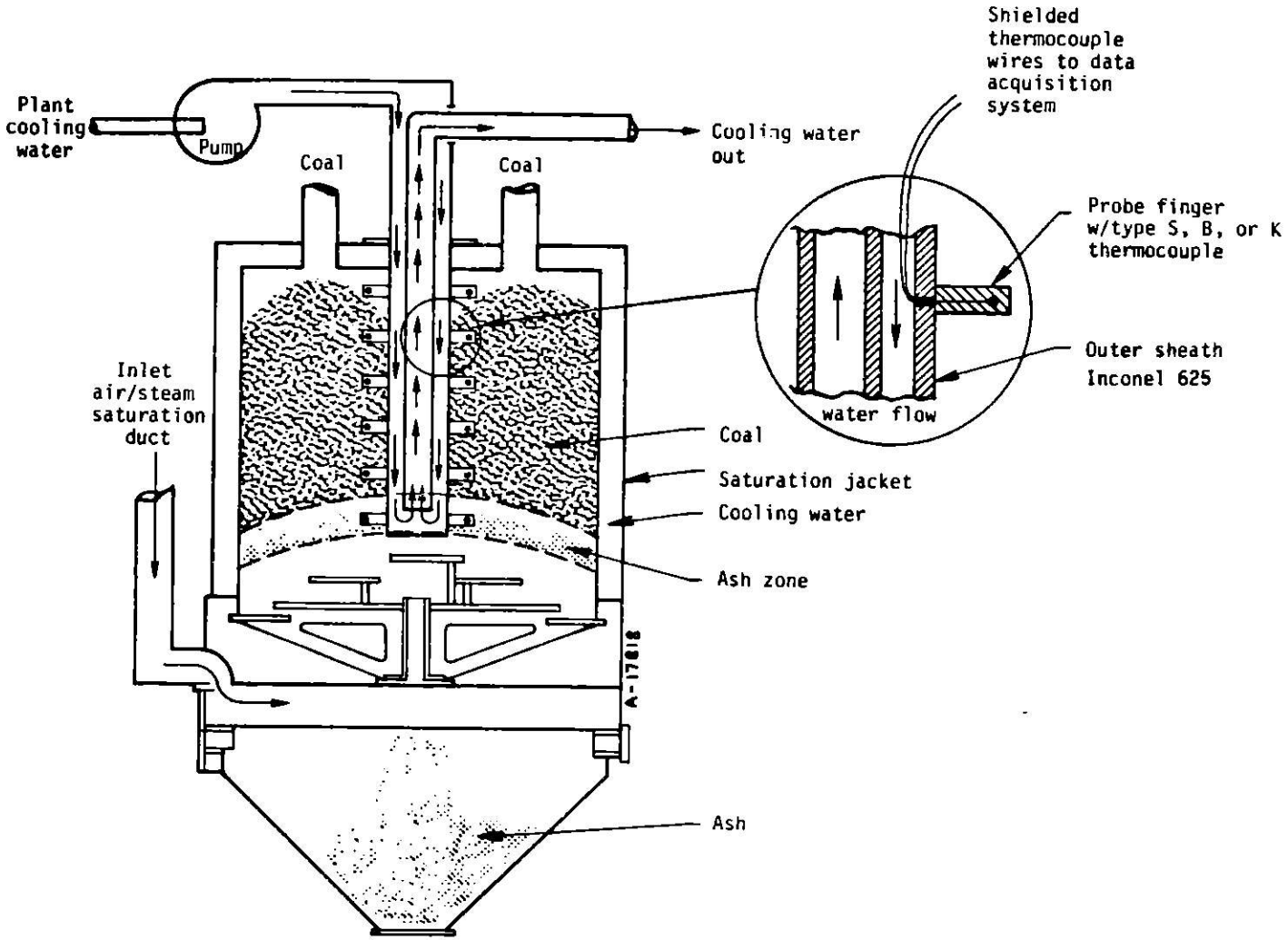

Figure 5. Vertical probe concept for continuous bed instrumentation.

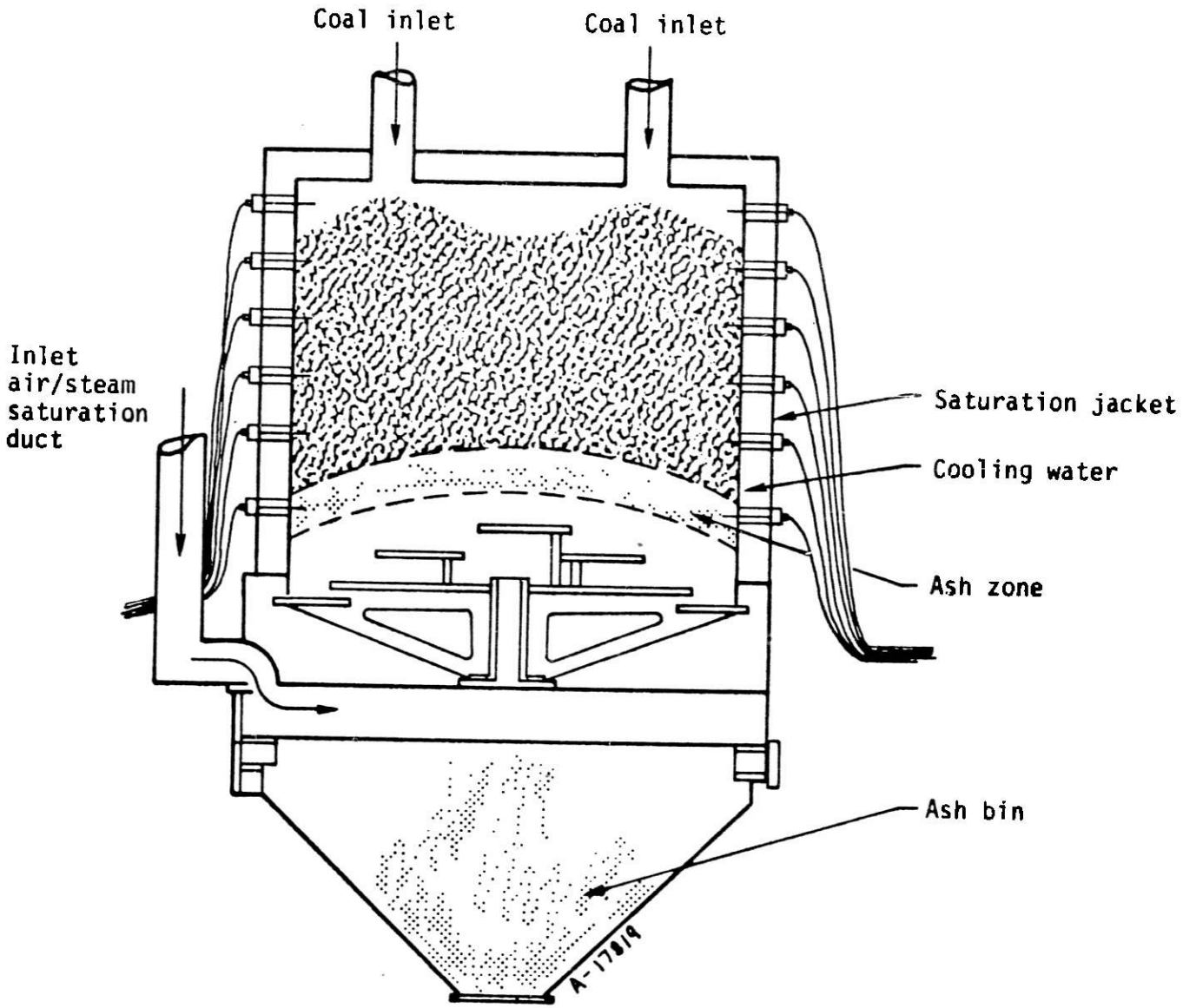

Figure 6. Sidewall probe concept for continuous bed instrumentation.

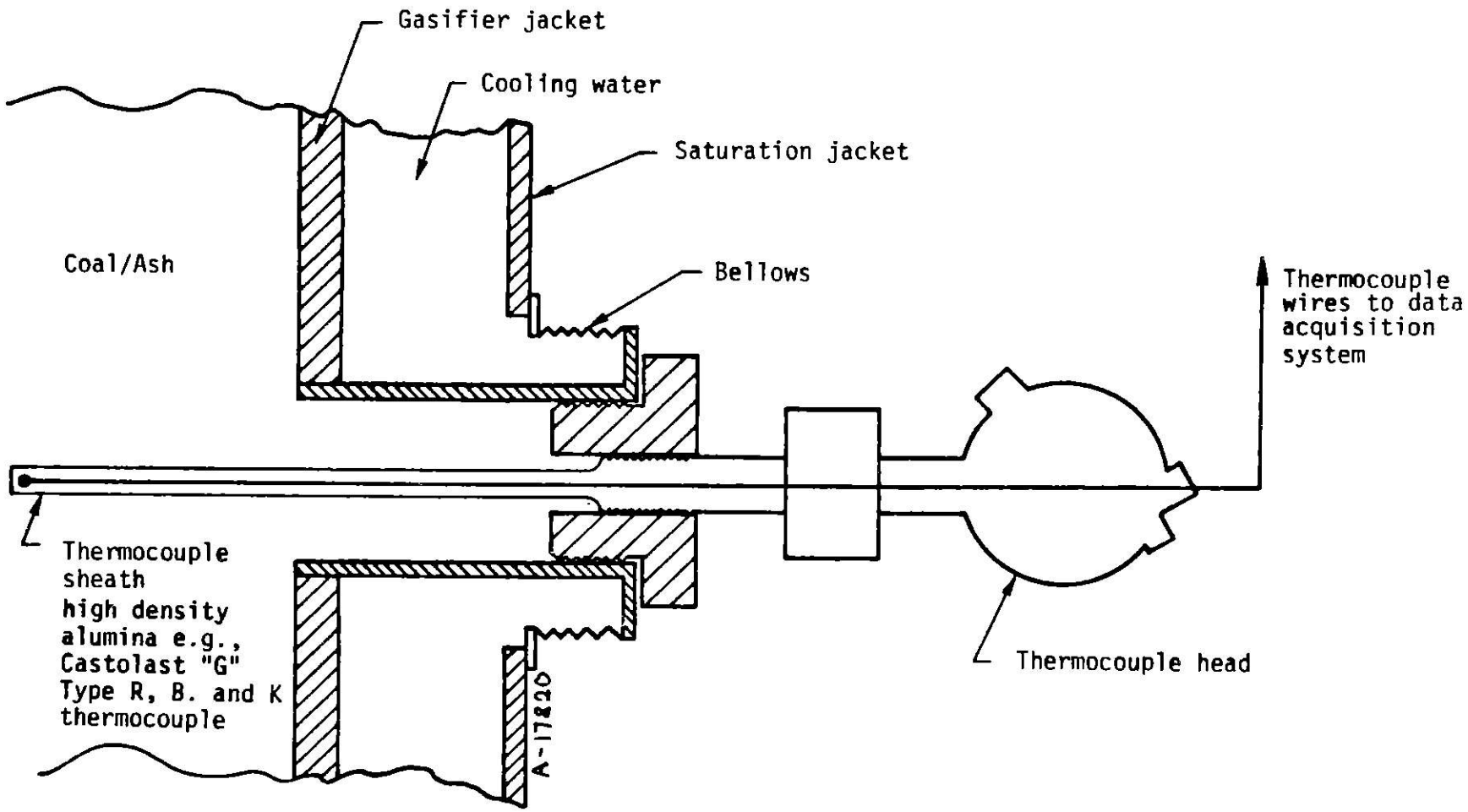

Figure 7. Detail of sidewall thermocouple probe designs.

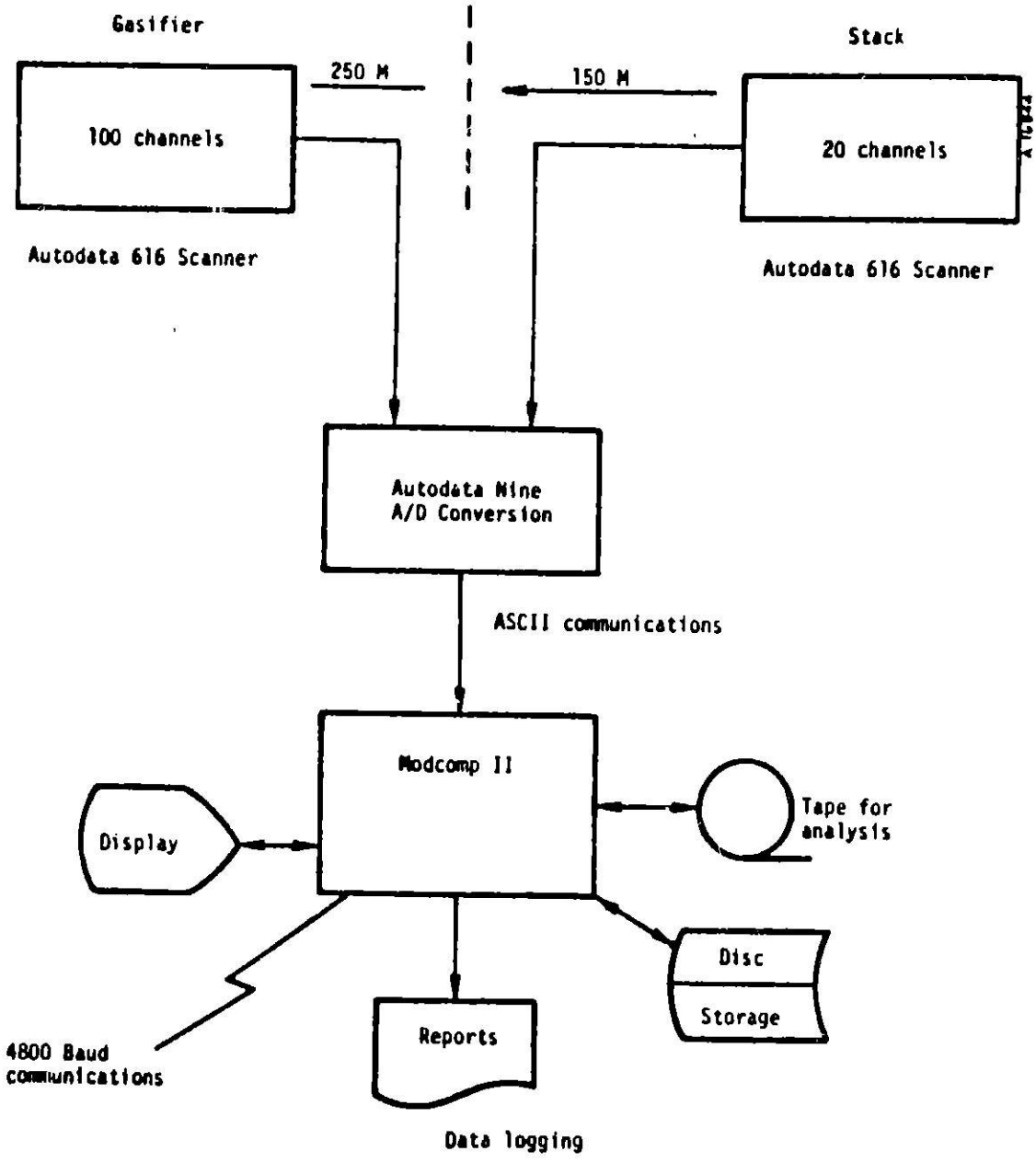

Figure 8. Schematic of data acquisition system for Glen-Gery gasifier instrumentation and evaluation.

QUESTION AND ANSWER

R. E. Maurer

Aerotherm Division/Acurex Corporation

R. F. Stewart, Morgantown Energy Research Center

Q. Have you considered level and density guages such as used on stirred bed producer at Morgantown?

A. No, we haven't. I presume you're referring to density being a distinction between the ash and the unreacted coal. I'd be interested in talking to you about that. We have not as far as reactor bed monitoring.

COAL STREAM COMPOSITION ANALYSIS FOR PROCESS CONTROL USING PROMPT NEUTRON ACTIVATION ANALYSIS

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Science Applications, Incorporated
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COAL STREAM COMPOSITION ANALYSIS FOR PROCESS CONTROL USING PROMPT NEUTRON ACTIVATION ANALYSIS

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H. Bozorgmanesh, and V. Orphan
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ABSTRACT

In this paper we describe early results of a series of laboratory experiments and computer modeling studies designed to provide realistic accuracy limits for the determination of the elemental concentration in coal using prompt neutron activation analysis (PNAA). The results provide guidance for optimizing the technique for monitoring the quality of coal which is being input to an electric power generating plant. The reported work was performed as the initial phase of an ongoing program to develop a prototype on-line coal analyzer based on the PNAA technique for power plant application.

1. INTRODUCTION AND BACKGROUND

The expanded role of coal in helping to meet U. S. energy needs has increased the demand for more rapid, accurate and reliable measurement of coal quality throughout the fuel cycle. Important operational and cost benefits can result if coal quality, namely calorific value and sulfur and ash contents, can be determined in a timely fashion at various locations: at the mine, when coal is fed into storage bunkers, at the coal preparation and cleaning plant and when feeding the boilers at the electric power station.

The traditional ASTM wet chemical analyses are too slow to meet the present needs for quality control at a time when coal quality is generally deteriorating - ash content is increasing while calorific content is decreasing.

The availability of accurate measurement techniques which can determine the constituents of coal in near real time on a large fraction of the coal throughput may provide the user with information which can bring more efficient utilization of the fuel, namely:

- provide for total heat management at a utility power station
- predict and avoid boiler slagging or fouling episodes in utility boilers
- meet SO_2 and particulate emission regulations more effectively
- provide the means of schedule and optimize power system load flow more efficiently

Nuclear techniques are well suited for providing these needed measurements. One nuclear technique in particular, Prompt Nuetron Activation Analysis (PNAA) holds promise as a means for providing rapid, representative and accurate compositional analyses of bulk coal which can be used to monitor coal quality. In the PNAA technique, elemental analysis of bulk coal is performed by bombarding the coal with neutrons, observing the resultant thermal neutron capture gamma-rays and quantifying the amount of each element by measuring the intensity of the characteristic gamma-rays from each element.

Figure 1 illustrates the possible role of the PNAA technique in the coal fuel cycle. Three points at which PNAA can be profitably employed are as follows:

- Power Plant Feed Control PNAA can assure real-time control on the quality of coal feed to electrical generating plants.

- Process Control PNAA can be used to monitor on-line the effectiveness of coal preparation and cleaning processes.

- Mining Borehold PNAA instruments can be used to measure in situ the coal quality and, hence, lead to a more effective planning of mining operations.

Four typical coal compositions, given in Table 1, illustrate the great variability in the composition of coal. This variability along with the inhomogeneous nature of coal makes it desirable to monitor coal stream compositions in a near continuous manner and over as large a sample volume as possible. The various coal constituents have different effects

Table 1. Four Typical Coal Compositions

PARAMETER	Illinois Bituminous (%)	West Virginia Bituminous (%)	Wyoming Sub-Bituminous (%)	North Dakota Lignite (%)
Moisture	6	1	25	37
Volatile Matter	36	17	30	27
Fixed Carbon	46	77	41	32
Sulfur	2.7	0.74	0.3	0.4
Ash	12	5	4	4
o SiO_2	48	60.0	24.0	41.8
o Al_2O_3	18	30.0	20.0	13.6
o TiO_2	0.8	1.6	0.7	1.5
o Fe_2O_3	20.1	4.0	11.0	6.6
o CaO	6.0	0.6	26.0	17.6
o MgO	1.0	0.6	4.0	2.5
o Na_2O	0.6	0.5	0.2	0.6
o K_2O	2.0	1.5	0.5	0.1
Btu/lb	13,500	15,500	9,750	7,600

on the coal behavior. Hence, it is highly desirable to determine as many of these elements as possible. The PNAA technique is very suitable for such measurements.

The feasibility of using PNAA to perform elemental analyses on bulk coal samples has been investigated in a number of laboratory studies[1-10] and a prototype instrument for sulfur analysis[11] has been developed. Although these studies demonstrated the applicability of the PNAA technique to coal, a quantitative assessment of the sensitivities and accuracies achievable for a range of important coal elements under realistic practical conditions is currently required. Furthermore, studies aimed at optimizing the technique (for example, by choice of gamma-ray detectors, source and source-detector geometry) for specific applications will provide the type of information required to ultimately implement PNAA in a coal process control application.

In this paper we describe results of a series of laboratory experiments and computer modeling studies designed to provide realistic accuracy limits for elemental concentration determinations in coal using the PNAA technique and to identify means of optimizing the technique for monitoring the quality of coal being input to an electric generating plant. The reported work was performed as an initial phase of an ongoing program to develop a prototype on-line coal analyzer for power plant application.

A summary of the major developmental challenges which must be addressed in the design of a prototype continuous nulcear analyzer of coal*, will help understand the rationale

*The acronym, CONAC for Continuous Nuclear Analyzer of Coal, will be used in the rest of this paper.

for the modeling and experimental studies described in the following sections. Major developmental problems are as follows:

- Design mechanical configuration compatible with coal handling facilities
- Signal-to-background may limit accuracy achievable for some elements
- Gamma-ray peak interferences may limit accuracy
- Detector count rate limitation
- Neutron activation and radiation damage of detector
- Inaccuracies introduced by bulk density variability
- Inaccuracies introduced by moisture and hydrogen content

The following sections describe initial efforts aimed at solving some of these problems and present results of an estimate of elemental sensitivities achievable with CONAC.

2. CONCEPTUAL MECHANICAL CONFIGURATION OF CONAC

A successful implementation of an advanced technique such as PNAA in the coal area requires that contraints imposed by the coal handling system will be considered from the outset. Hence, the possible integration of any conceptual configuration into conventional coal handling system has been proposed early in the program and is illustrated in Figure 2.

The ability of the CONAC to analyze large samples of the throughput (1 to 20 tons/hour) enables its intorduction after the primary sampler. Therefore, the CONAC sample is much more representative of the primary coal stream than the small sample, obtained after tertiary sampling, for conventional laboratory analysis.

Principal advantages of CONAC in general and in the proposed configuration in particular are as follows:

- Samples a large, more representative sample
- Sample size can readily be changed
- Nondestructive
- Non-obtrusive
- Provides on-line and near real-time analysis
- Single measurement provides multiple coal quality data

Proper presentation of the coal to the CONAC system is necessary in order to insure the minimization of spurious

signals. However, achieving a non-segregated sample presentation is difficult if not impossible to attain. Therefore, controlled segregation is desirable. This requires consideration of the bulk properties of the material, its rheological behavior and the geometry of presentation.

A flowing stream of particles incorporates more difficulties than a moving bed of particles*. As a result, incorporating concepts similar to those employed in belt feeder systems may be one way to avoid bin flow and chute problems. In addition, how the material is presented to the system conveying the material to the CONAC system is quite important. Since controlled segregation is also a function of particle size, finer material may be needed, thereby requiring size reduction and hence sampling of the streams rather than full presentation of the entire streams.

The static and dynamic properties of coal particles of different sizes have direct bearing on the acceptability of the various mechanical configuration for a continuous nuclear coal analyzer. As was indicated above a measurement of static coal particles, as represented by a moving belt, may be the prefered configuration also from the coal-handling point of view. However, a bin of coal with a neutron source at its center is the most favorable configuration from the neutron physics point of view. This is indeed the arrangement used in the previous experiments[11].

*For example, the accelerating particles open up the bed of material which causes bulk density variations and may cause particle migration due to size and specific gravity differences.

Based on the present knowledge and taking into account nuclear considerations two basic generic configurations are considered in the present study (see Figure 3):

a) Inner source configuration in "bin" and "belt" geometries.

b) Outer source configuration in "bin" and "belt" geometries.

These source configurations are tried both in "bin" and "belt" type geometries - thus covering the most promising approaches. These geometries provide the basis for the calculation and experiments which will finally lead to the recommended configuration for CONAC.

3. ANALYTICAL CALCULATION

A series of neutron and gamma-ray transport calculations are being carried out. The purpose of these calculations is to understand the complex interplay between the various factors that influence the signal from which the weight percent of each elemental constituent of coal is determined. The signal is obviously the gamma-rays emitted following the capture of neutron by the nuclei of the specific elements. The most important factors are:

- Hydrogen content
- Coal bulk density and its variability
- Thickness or diameter (depending on the geometry), of coal sample, and
- Variation of coal composition

The affect of these factors has been studies with the aim to identify if possible, configurations which will minimize the influence of those factors which are difficult to control.

The measured gamma signal depends on the strength and distribution of the neutron flux in the coal. Since absorption and leakage probabilities depend on sample composition and hydrogen content neutron flux may vary from coal to coal. Typical results on the effect of coal composition on the spatial distribution of the thermal flux are shown in Figure 4 for 70 cm diameter sphere with two different types of coal: North Dakota and Illinois. The first one has a higher moisture content (cf. Table 1) resulting in a higher themalization near the source (at the center) and lower neutron flux

at the outer surface. The constant flux region at the center is due to lack of thermalization of neutrons in the lead surrounding the source. Figure 5 shows the calculated energy spectra of the gamma leakage from the two types of coal. These spectra show the combined effect of changes in composition and neutron flux distribution. Illinois coal has a higher sulfur and iron content (cf. Table 1) which accounts for the higher gamma intensity at the higher energy range. The higher flux intensity at energies below 2.2 MeV observed in the North Dakota coal is due mainly to (Compton) scattering in the sample of the hydrogen capture gamma.

The effect of sample size and bulk density was studied for various types of coal. Increasing the bulk density has two opposite effects. On the one hand, it enhances the production of prompt gamma-rays. On the other hand, it increases the self attenuation of gamma-rays in the sample, thus reducing the measured signal. The relative magnitude of these two effects depends on the sample thickness, coal composition, gamma energy and neutron source spectrum. Typical results for the effect of size and density on the leakage of gamma-rays for four energy ranges is shown in Figure 6. The normalized gamma-ray leakage for one energy interval (3-4 MeV) as a function of bulk density for two geometries: sphere and slab is shown in Figure 7. Both figures indicate that the two opposing phenomena, namely neutron production and gamma self attenuation, lead to a system where the gamma leakage is practically independent of the bulk density of coal. This is a useful feature since it is not easy to control the bulk density of coal. Other calculations were made to determine the effect of variations in the distribution of the bulk density within the coal sample and the interaction between various elements especially between hydrogen and the rest of the coal constituents.

4. LABORATORY EXPERIMENTS

Preliminary Measurements - Bin Geometry

Prior to the current effort a preliminary study of capture gamma rays from coal was made at Science Applications, Inc. A sketch of the experimental set-up is shown in Figure 8. The geometry, which simulates the bin concept, consisted of a 200 lb. sample of coal in a plastic container. A 5μg ^{252}Cf neutron source (10^7 neutrons/sec) was positioned at the center of the coal in a PVC tube. Small lead shadow-shields were placed in the coal between the source and detectors. External neutron shielding was provided by layers of borated wax.

Capture gamma-ray spectra were obtained with both a 30 cm^3 (~8% efficiency at E_γ=1.33 MeV) Ge (Li) and a 5"x6" NaI detector. The high energy portion of the Ge(Li) spectrum is shown in Figure 9. The identified peaks are labeled by the energy of the gamma-ray of the element responsible, and whether the peak is a single escape (SE) or a double escape (DE) peak. Peaks were identified corresponding to neutron capture in H, B, N, C. Al, Si, S, Cl, K, Ti, Cr, Fe and Pb.

Figure 10a shows the spectrum obtained by the 5"x6" NaI detector. The resolution of this detector, at E_γ= 662 KeV, was 10.2%. Prominent peaks corresponding to capture in the boron shielding (0.477 MeV) and hydrogen (2.223 MeV) are clearly visible. Additional peaks at 3.53 and 4.92 MeV are less clearly visible. Further peak information would be difficult to obtain from this raw data. A preliminary analysis of the high energy portion of the NaI spectrum has been carried out using the computer code MAZE[12]. Figure 10b shows the preliminary unfolded spectrum above 2.5 MeV. Also

shown are the positions and approximate photo-peak intensities of the gamma-rays identified in the Ge(Li) spectrum. It is seen that the code has separated the strong lines corresponding to Si, Cl and Fe. The weaker lines will not appear in the unfolded spectrum until better convergence is obtained. In addition to the strong lines, there are several peaks in the unfolded NaI spectrum that do not appear in the Ge(Li) spectrum. The lines at 4.325 and 7.831 MeV do not correspond to incident gamma-rays. It is suspected that these lines (and to some extent the peak at 6.477 MeV) are due to neutron capture in the NaI(Tl) detector.

Current Experiments

The current effort* involves well defined laboratory scale experiments to study the effect of various operational parameters for optimal system design. Analyzed coal samples of known composition are used to determine the system performance.

A schematic of the experimental set-up is shown in Figure 11. It consists basically of a 200 Kg sample of coal in two rectangular wooden containers with a shielded Cf-252 neutron source (about 5μg; 10^7 neutrons/sec) at an off-center location. Special attention was given to the structural materials used in the set-up to prevent interference with the responses from the coal constituents. A 20% Ge(Li) detector (85 cm^3) shielded with 5 cm of borated epoxy is used to measure the capture-gamma spectra.

Large amounts of spectral data have been obtained pertaining to the effects of changes in the following

*Supported by the Electric Power Research Institute, Palo Alto, California.

parameters on system performance:

- Coal thickness
- Coal bulk density
- Neutron source shielding
- Detector shielding
- Source-to-detector distance, and
- Presence of a gap between the two coal boxes

Measurements were made using high-sulphur Pittsburgh #8 and low-sulphur Wyoming bituminous coals. A portion of a gamma-ray spectrum from the two types of coal in the 5 MeV region is shown in Figures 12 a and 12b. Prominent peaks from sulphur (5420 KeV), carbon (4945 KeV) and silicon (4934 KeV) from chlorine and others are evident in the figure. More than approximately 100 gamma-ray lines have been identified from 14 elements, including those elements important to coal analysis (hydrogen, carbon, silicon, aluminum, sulphur, iron, nitrogen, sodium, potassium, titanium, and chlorine). The large difference in the sulfur and iron content of the two types of coals is very obvious even from the raw data shown in Figures 12a and 12b. Another major difference is in the amount of chlorine which is not measured routinely in the conventional ASTM destructive techniques.

Based on gamma-rays that have been observed from high-sulphur Pittsburgh #8 coal, a first estimate can be made of the projected count rates and measurement precision of various elements, as listed in Table 2. The numbers will vary somewhat for coals of different composition.

Table 2. Projected Precision of Coal Elemental Analysis Using the PNAA Technique*

Element	Peak Counts Counts/Minute	PRECISION Relative** (%)	PRECISION Absolute*** (WT %)
H	84,500	1.0	0.05
C	2,320	2.0	1.5
S	5,890	1.5	0.04
N	210	7.0	0.1
Si	1,390	2.5	0.05
Al	1,670	2.5	0.03
Fe	4,600	1.0	0.02
Ca	26	20.0	0.02
Mg	18	20.0	0.01
K	741	5.0	0.005
Na	190	15.0	0.005
Ti	870	3.0	0.001
Cl	8,370	1.0	0.001

*100 micro-gram Cf-252 source, 20% Ge(Li) detector, 30cm coal thickness, 10 minute counting time and using net counts in all major peaks for each element. Based on measurements with Pittsburgh #8 bituminous coal.

**Peak-to-background under peak ratio taken to be 1/4 for this estimate.

***Will depend on actual coal composition; these values are for a "typical" bituminous coal.

Gamma-ray data have also been obtained for the two coal samples using 3"x3" and 5"x6" NaI detectors. The aim is to determine how much information can be obtained about coal elemental composition from MAZE-enhanced NaI data (see Figure 10).

Continuing efforts in the experimental area include the following:

- High count-rate performance.

  The system must maintain good energy resolution (narrow peaks) at high data rates, to avoid loss of information.

- Lab Prototype.

  System performance will be tested in geometries compatible with realistic coal handling.

- Determination of practical achievable accuracies of various coal constituents.

- Feasibility of the determination of total hydrogen content and the moisture content by using nuclear and non-nuclear techniques.

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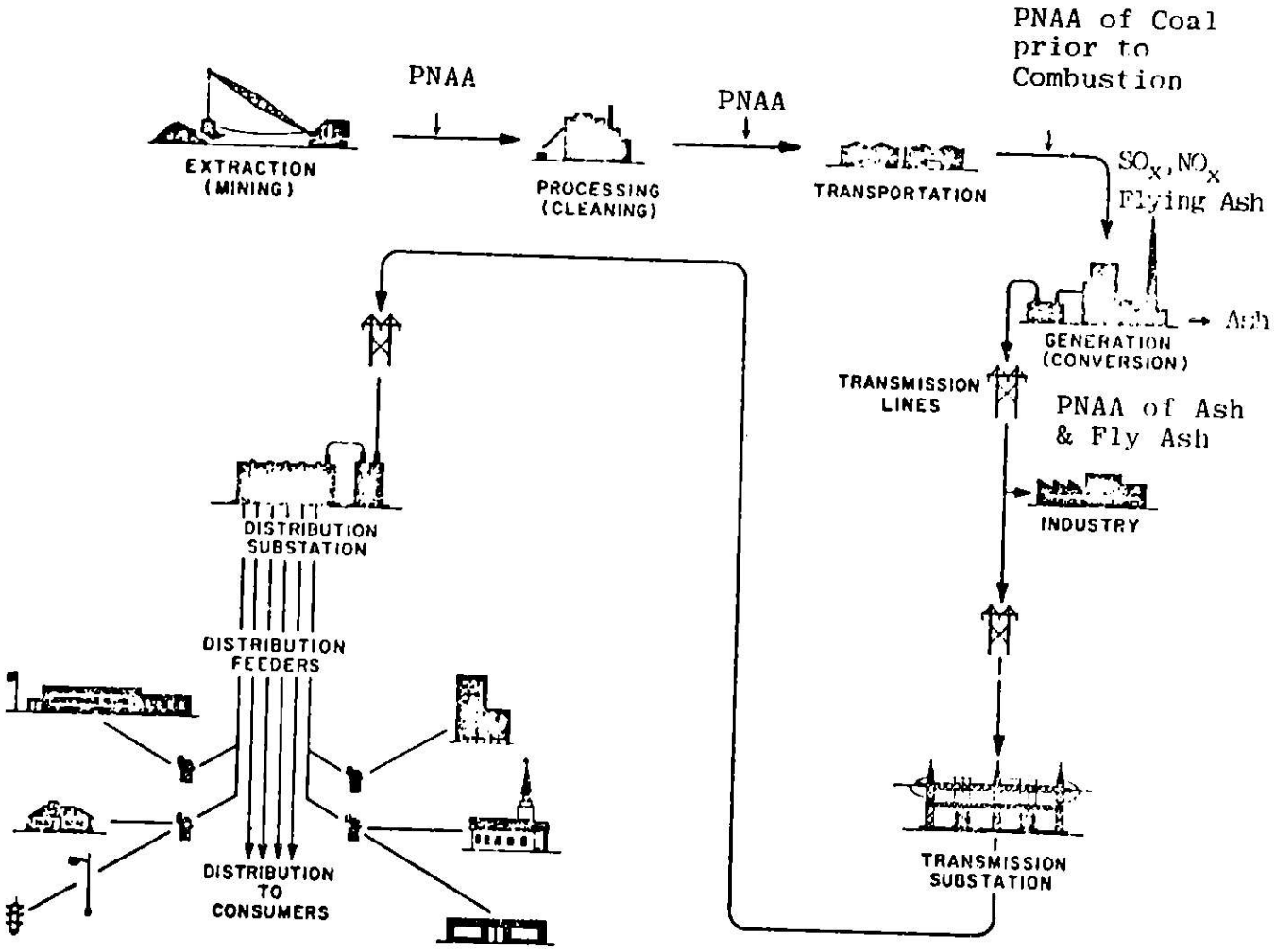

Figure 1. Schematic of Coal-Fired Electric Energy System with Indications where Nuclear Assay of Coal may be Useful and Possible

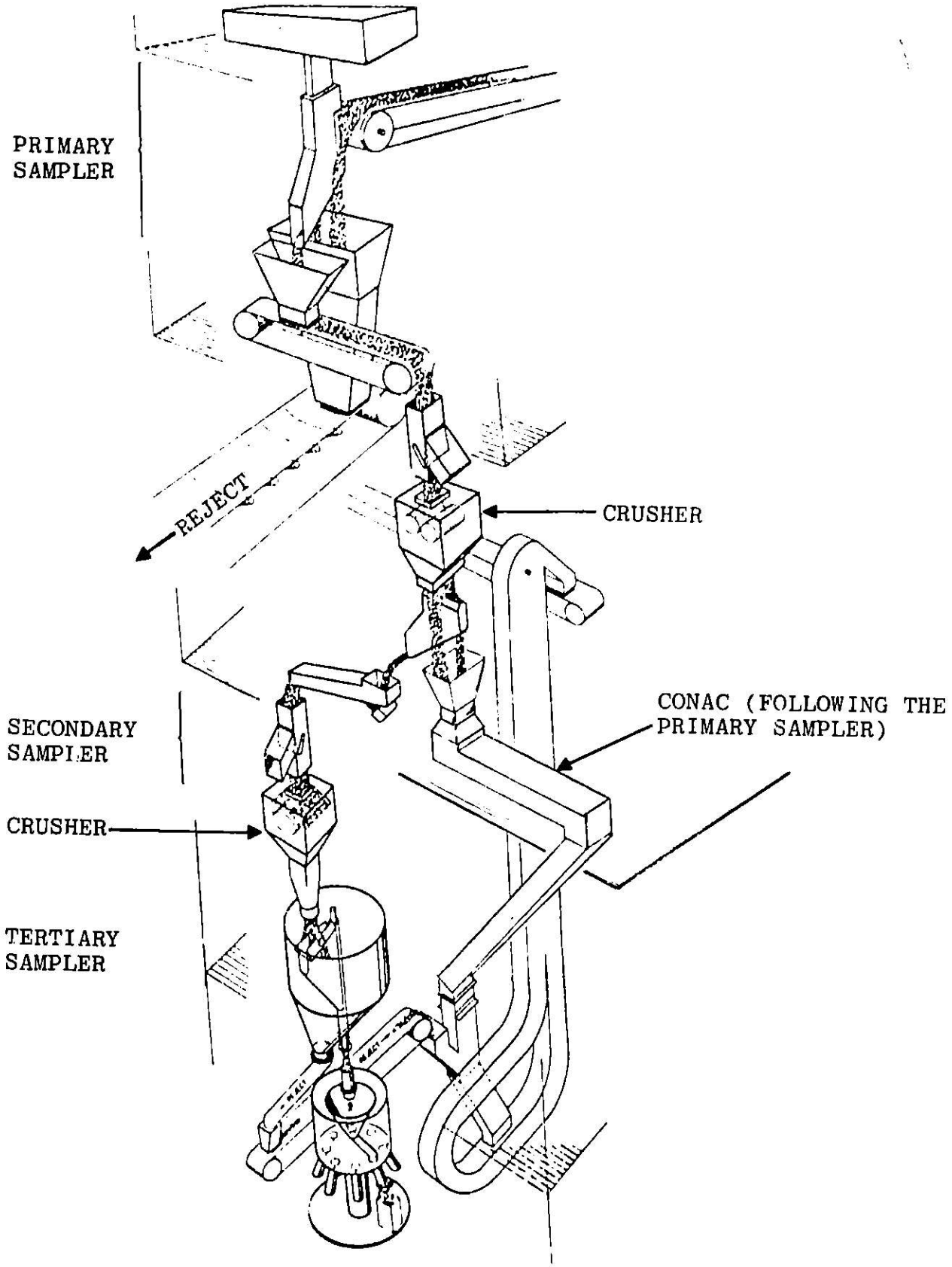

Figure 2. Schematic Illustrating Integration of CONAC in Coal Sampling System

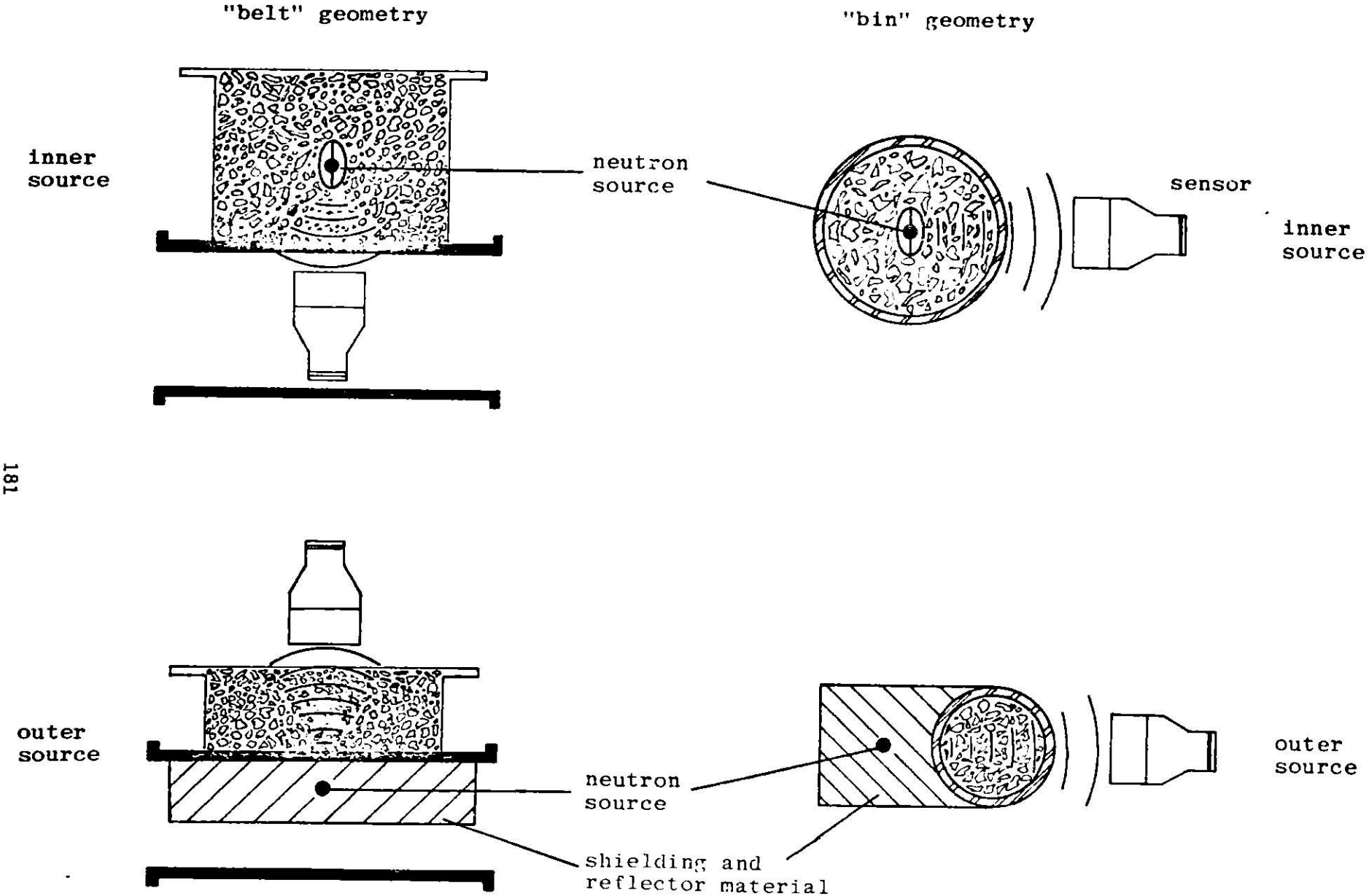

Figure 3. Conceptual Generic Geometrical Configurations for CONAC

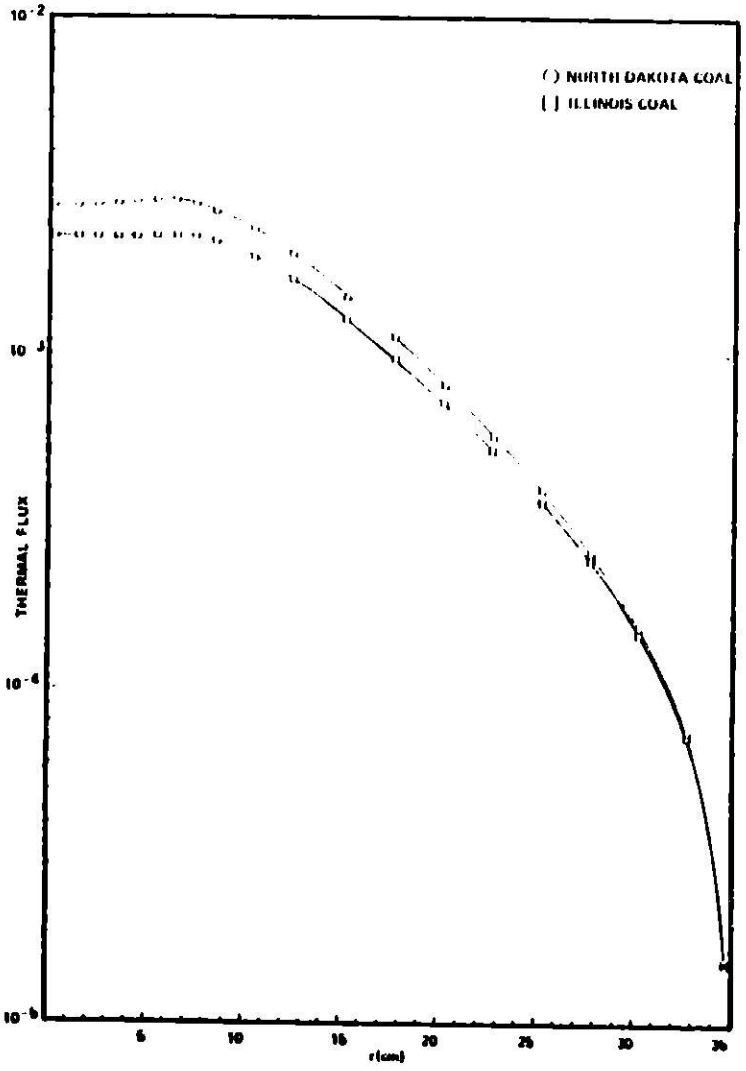

Figure 4. Thermal Neutron Flux Distribution in Bulk Coal

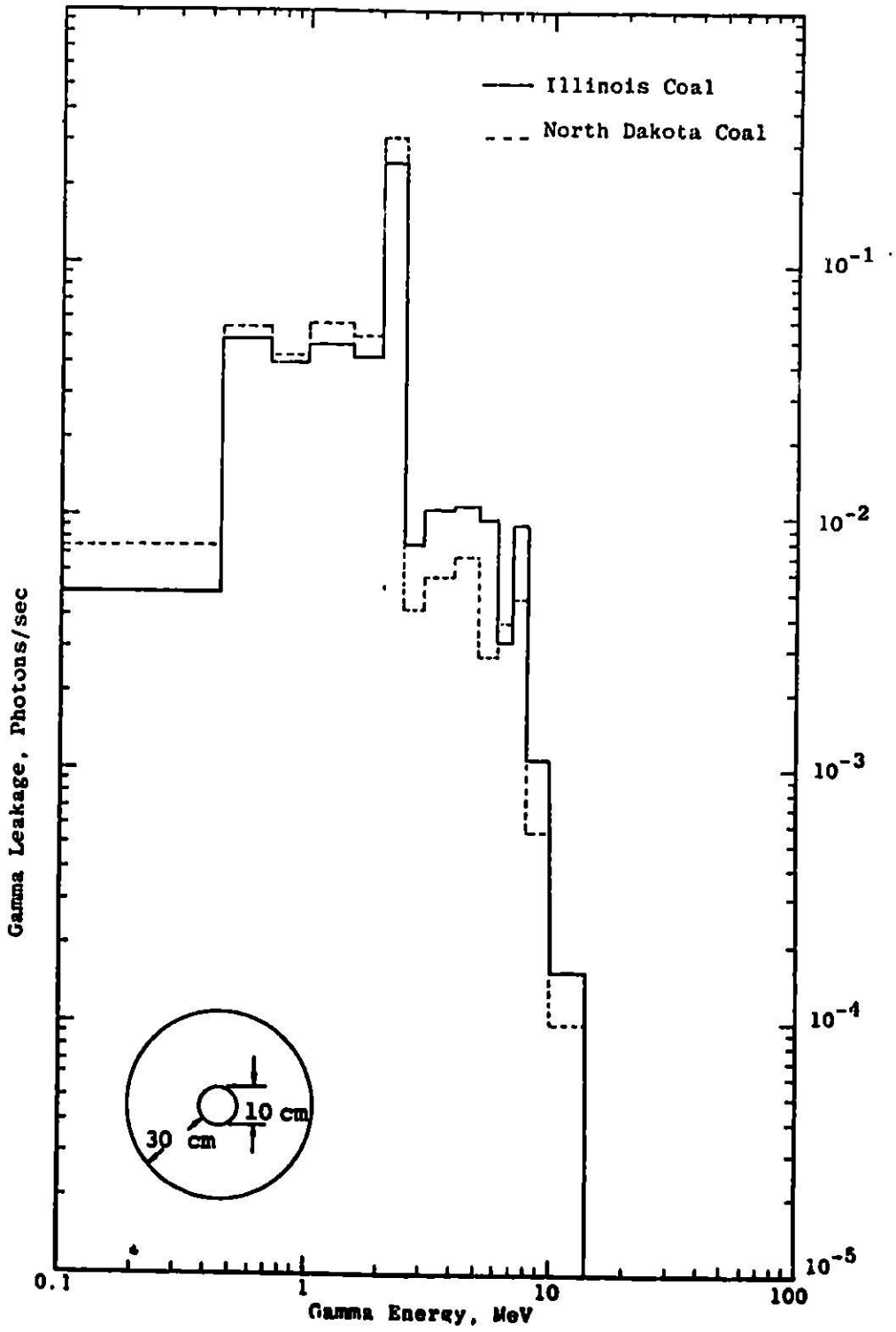

Figure 5. Gamma Leakage Energy Spectra

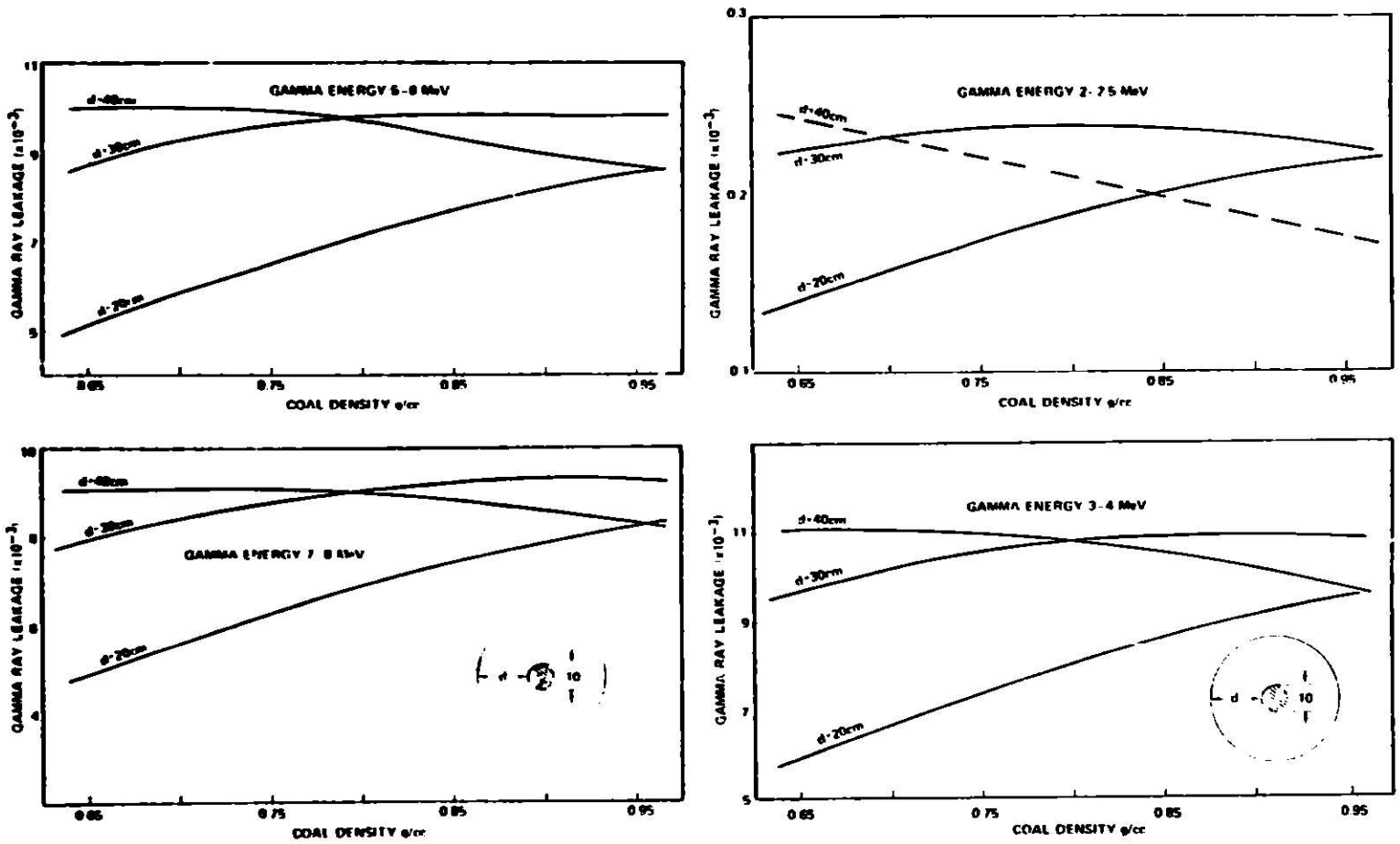

Figure 6. Effect of Density Variation on Neutron Capture Signal From Illinois Coal

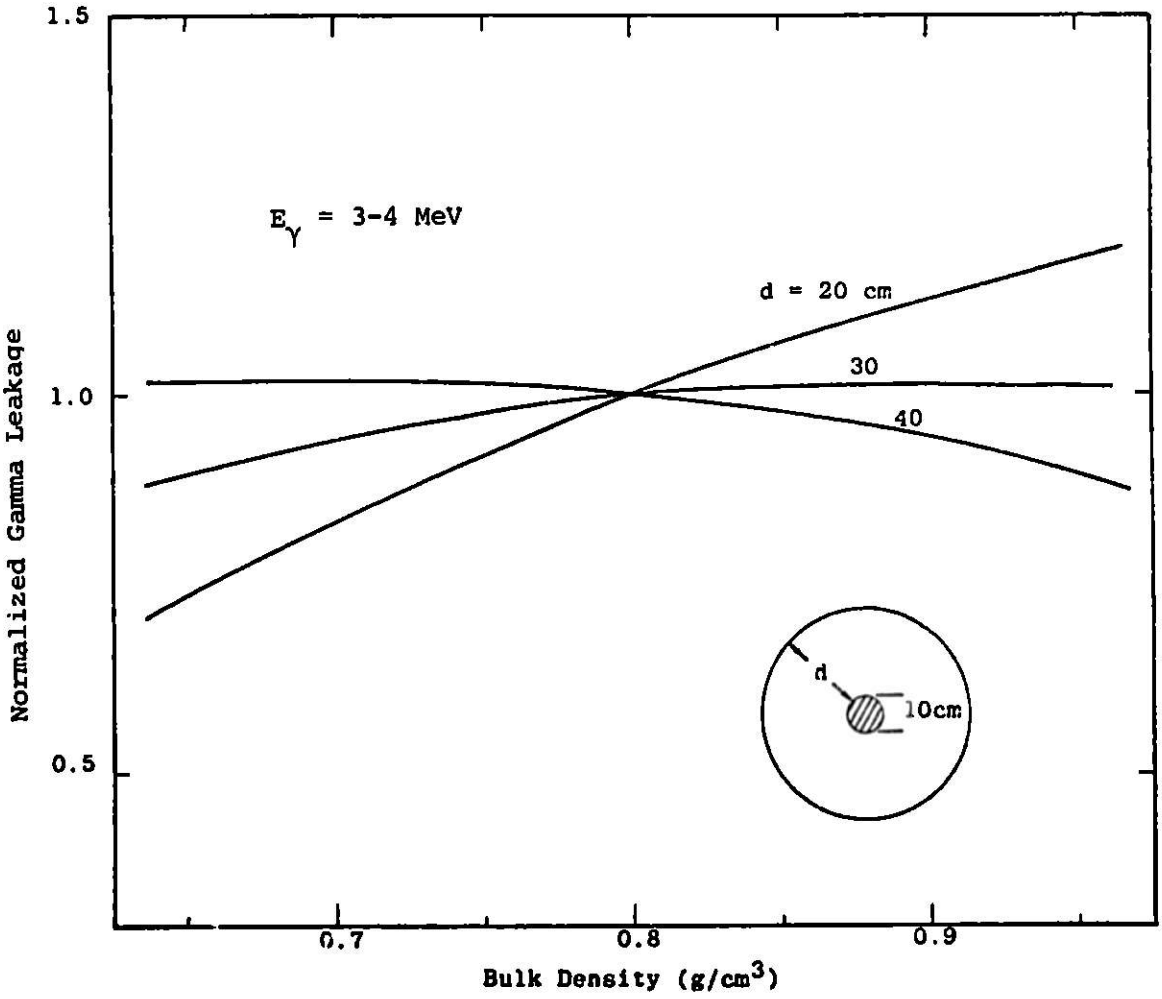

Figure 7a. Normalized Gamma Leakages vs. Density for Different Coal Thicknesses

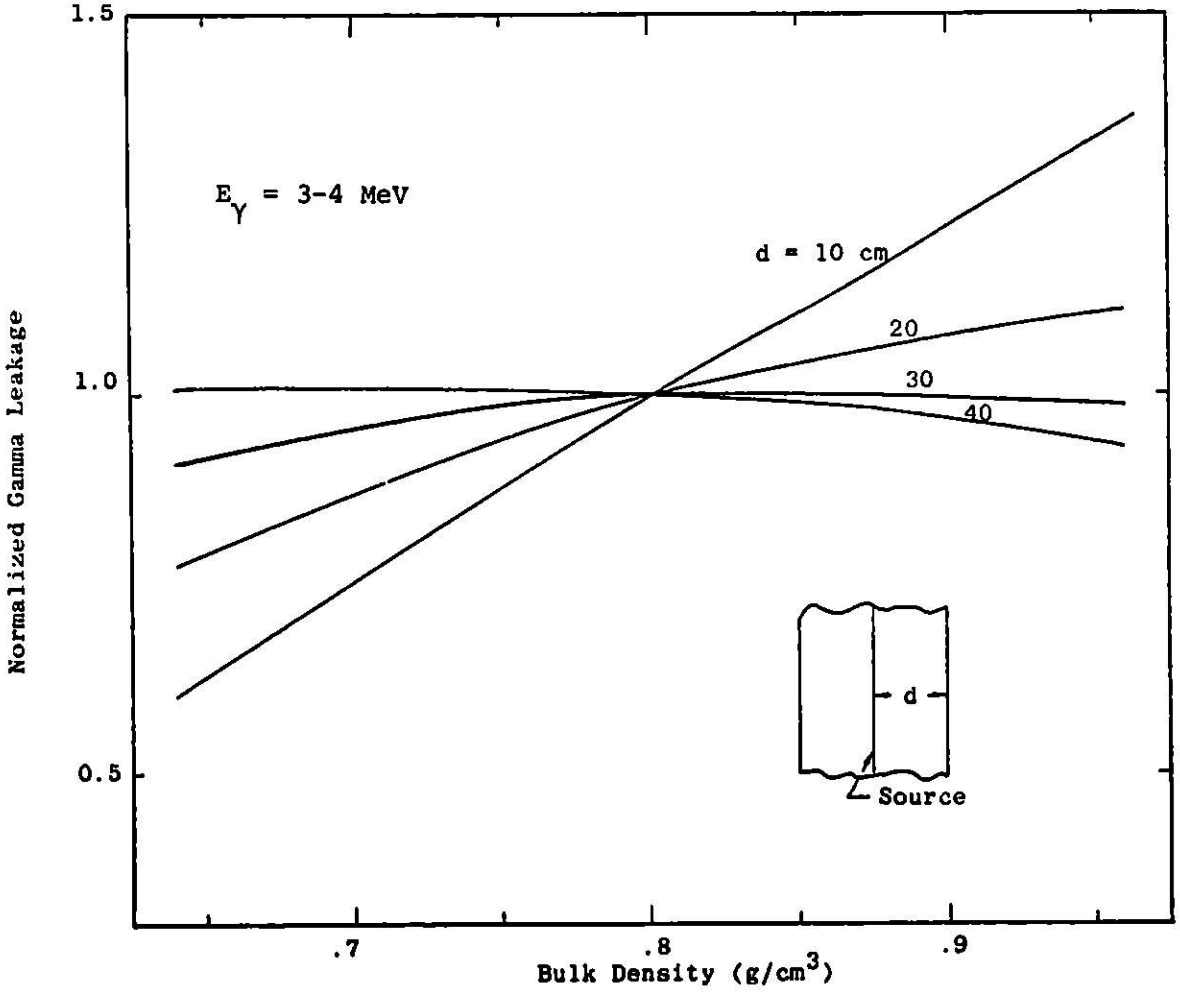
1.5
1.0
0.5
Normalized Gamma Leakage
E_γ = 3-4 MeV
d = 10 cm
20
30
40
d
Source
.7
.8
.9
Bulk Density (g/cm^3)

Figure 7b.

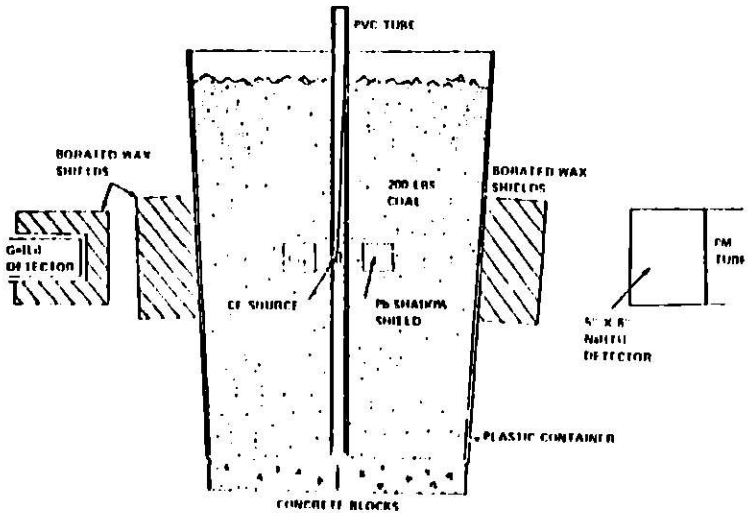

Figure 8. Preliminary Setup for Measuring Capture Gamma-Rays from Coal

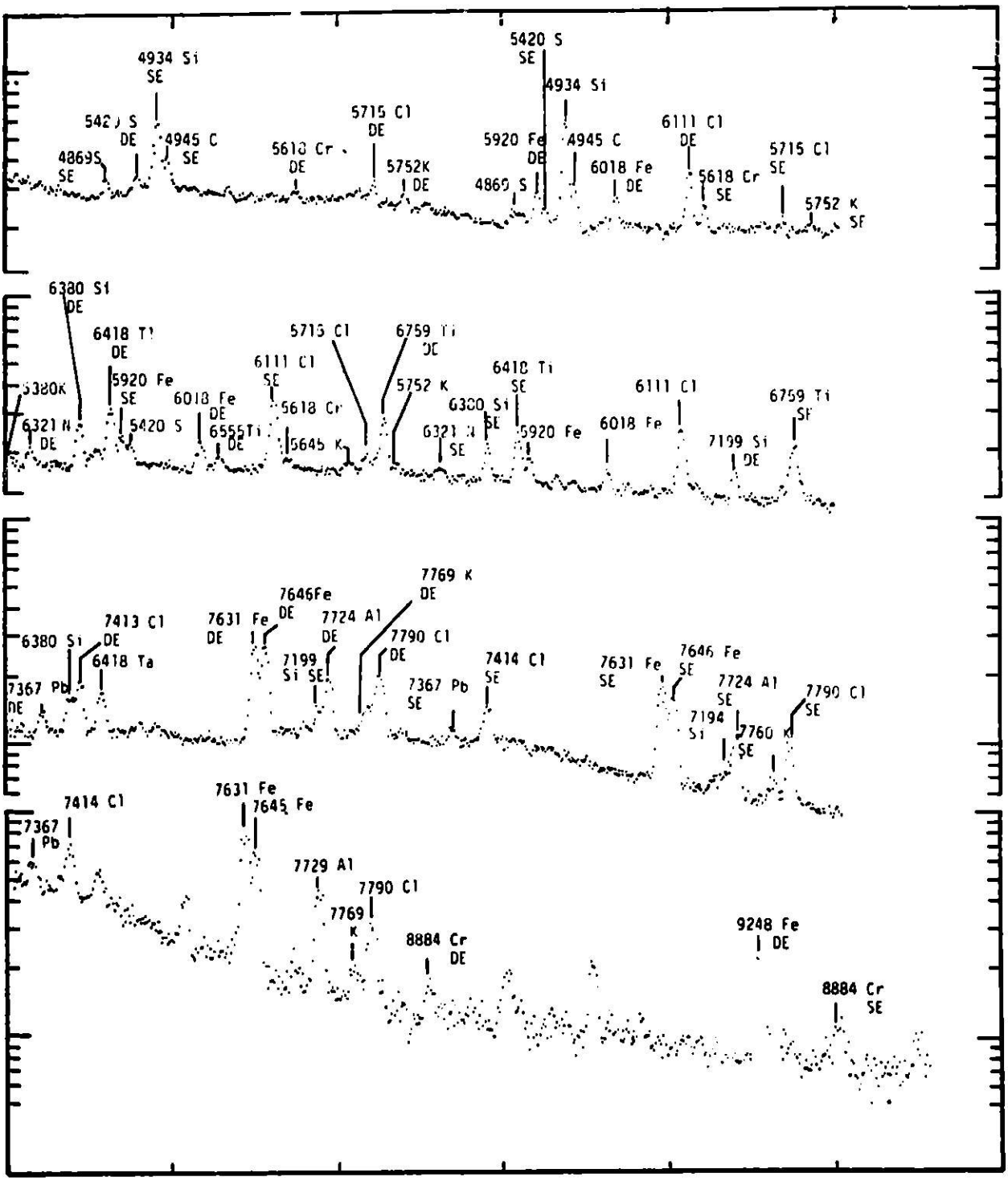

Figure 9. Gamma-Ray Spectrum from Coal Irradiated With Neutrons from a ^{252}Cf Source Measured With Ge(Li) Detector (High Energy Range)

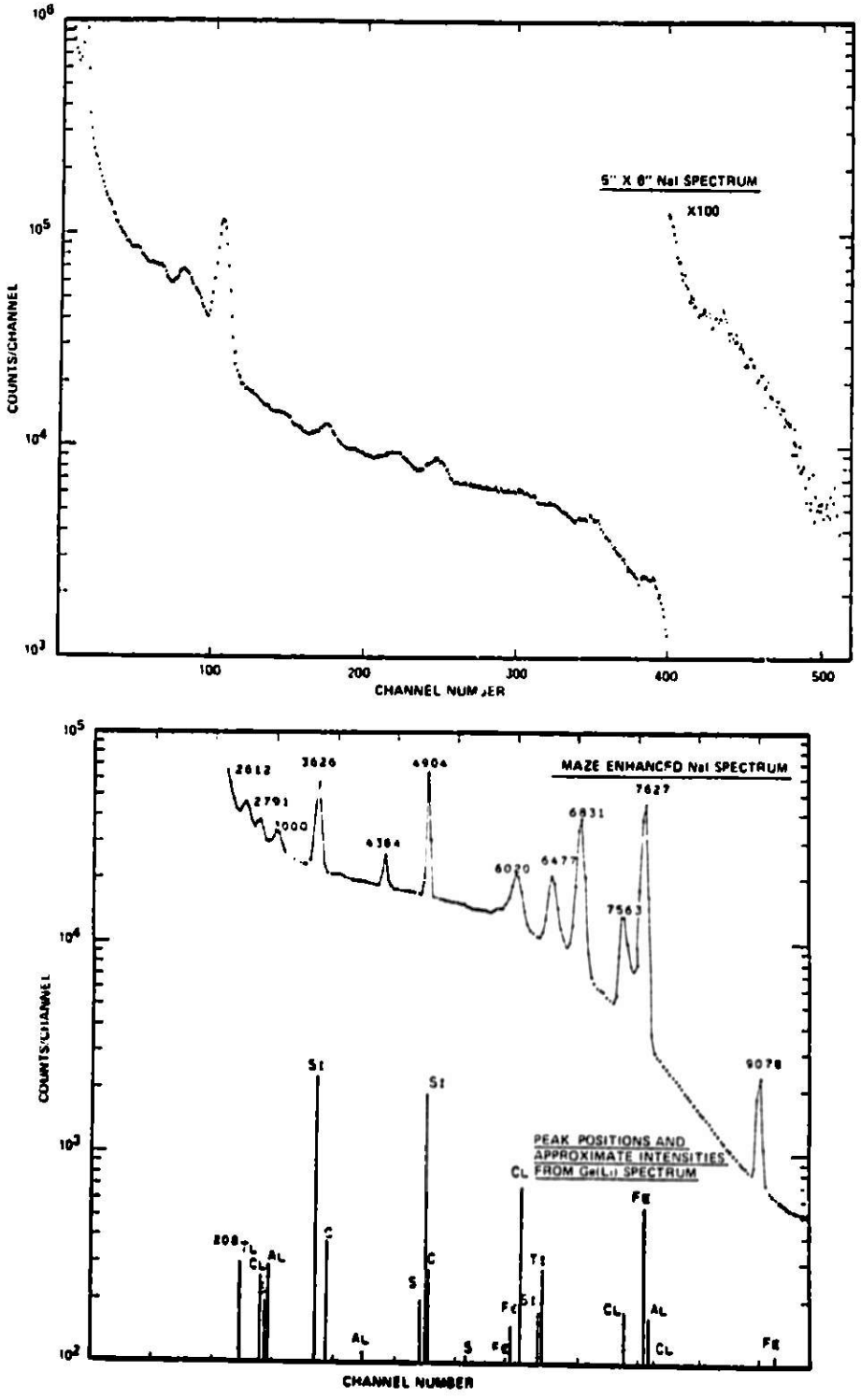

Figure 10. Capture Gamma Ray Spectrum From Coal Measured With NaI Detector

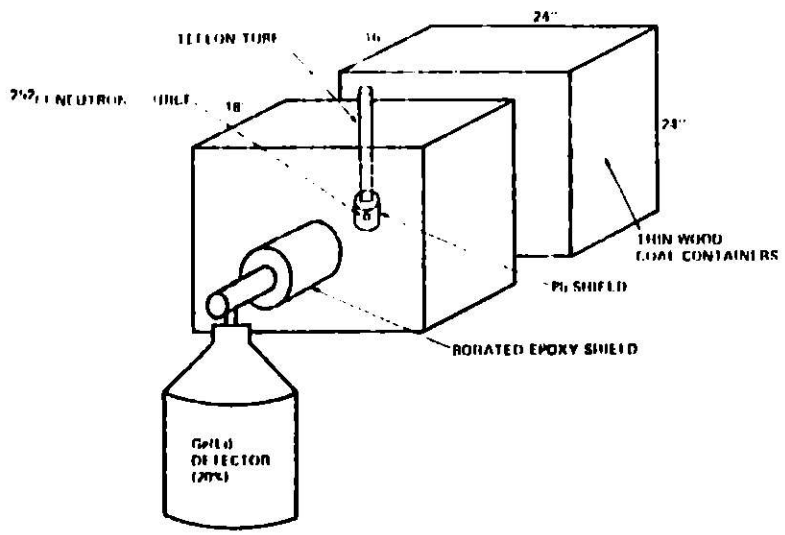

Figure 11. Schematic of Setup Used to Optimize Prompt Neutron Activation Analysis of Coal

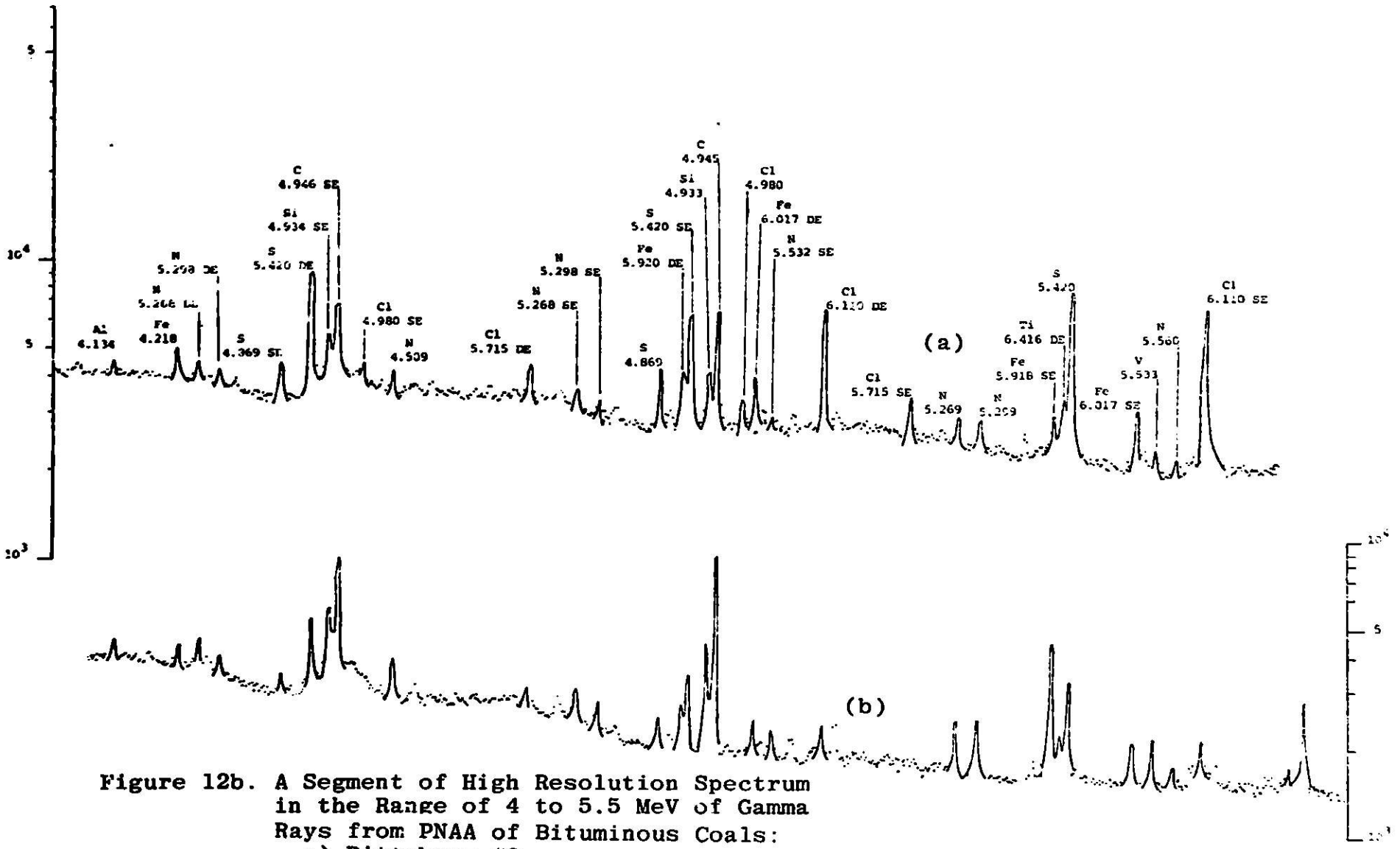

Figure 12b. A Segment of High Resolution Spectrum in the Range of 4 to 5.5 MeV of Gamma Rays from PNAA of Bituminous Coals:
a) Pittsburg #8
b) Wyoming

QUESTIONS AND ANSWERS

Tsahi Gozani

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B. G. Lipták, Lipták Associates

Q. How much of the 30 minutes measurement time is taken up by the computer for data analysis?

A. The answer depends on the methods of data analysis and the related hardware. It is quite conceivable that the data reduction will not add to the data acquisition time. While the data is being acquired the previously acquired data will be processed. The processed data may be available in a very short time if fair size computer is performing the job or longer if mini or microprocessor are used. Generally I don't believe that data analysis will be a serious problem in limiting throughput.

Q. What are the other factors in requiring 30 minutes for analysis?

A. The 30 minutes should provide enough time to accumulate sufficient statistically significant data on important elements, that is the time limitation. Longer time may be required for measurement of the minor elements e.g., K, Na. By the way, NaI detector gives statistically significant data within only several minutes, however it is difficult as of yet to obtain from it accurate information on elements except for hydrogen and sulfur.

R. W. Doering, Argonne National Laboratory

Q. Describe your unfolding process.

A. The unfolding code MAZE is an iterative code designed to remove the degrading effects of the detector, to minimize effects of statistical fluctuations and to construct an enhanced image spectrum that corresponds as closely as possible to the spectrum of radiation incident on the detector. The mathematical basis for MAZE is well documented (see Ref. 12 of our paper).

A. D. Young, The Foxboro Company

Q. What elemental analysis data is needed to be able to more efficiently control the coal gasification process?

A. Most of the elements that are of interest in the direct combustion of coal should, to different degrees, be of interest in the coal gasification process; notably properties of ash which are influenced by the amount of K and N.

Q. Has any attempt been made to estimate the quantitative benefits of elemental analysis in plant control?

A. A qualitative assessment of the benefits of prior on-line knowledge of elemental composition of coal in power plant were done at EPRI and some utilities. A more quantitative assessment is being conducted now.

Q. What is your estimate of the cost of such an elemental analysis system?

A. The CONAC system described in my paper is a very versatile one and could be tailored to specific requirements which may be less demanding than a full on-line elemental analysis of coal on the entire throughput. It is envisaged that the cost of element analysis system will be in the range of one ot several hundred thousand dollars.

BANQUET

Master of Ceremonies

M. J. Walsh
Procon, Incorporated and
Operations Vice President, Chicago Section,
Instrument Society of America
Chicago, Illinois

THE FUTURE OF COAL GASIFICATION IN ILLINOIS -- THE UTILITIES POINT OF VIEW

R. J. Eby, General Manager
Illinois Coal Gasification Group
Chicago, Illinois

THE FUTURE OF COAL GASIFICATION IN ILLINOIS - THE UTILITIES POINT OF VIEW

Robert J. Eby
The Illinois Coal Gasification Group

1. PRESIDENT CARTER'S ENERGY MESSAGE

President Carter, in his April 20 energy message to Congress summed up the nation's energy dilemma "We cannot continue to use our oil and gas for 75% of our energy consumption when they make up only 8% of our domestic supply. The principal oil exporting countries would not be able to satisfy all the increases in demand expected to occur in the United States and other countries throughout the 1980's. In 1976, the thirteen OPEC countries exported 29 million barrels of oil per day. If world demand continues to grow at the rate of recent years, by 1985 it could reach or exceed 50 million barrels per day. However, many OPEC countries cannot significantly expand production; and in some, production will actually decline."

"Natural gas supplies are also limited. In the United States, natural gas constitutes only 4% of conventional energy reserves, but supplies 27% of energy consumption."

The President's energy message continued "Conversion by industry and utilities to coal and other fuels would be encouraged by taxes on the use of oil and natural gas."

His plan also contains a strong regulatory program which would prohibit all new utility and industrial boilers from burning oil or natural gas, except under extraordinary conditions.

While promoting greater use of coal, the administration seeks to achieve continued improvement in environmental quality. A strong, but consistent and certain environmental policy can provide the confidence industry needs to make investments in energy facilities. The administration's policy would: require installation of the best available controlled technology in all new coal fired plants, including those that burn low sulfur coal; protect areas where the air is still clean from significant deterioration; encourage states to classify lands to protect against significant deterioration within three years after the Clean Air Act Amendments.

Coal development and production is most economical when it is near major markets. Although coal production will expand in many areas, there should be large production increases in highly populated eastern and midwestern regions, where use of coal by industry and utilities will grow considerably in the future. The required use of best available controlled technology for new power plants should stimulate even greater use of high sulfur midwestern and eastern coals.

Expansion of U.S. coal production and use is essential if our nation is to maintain economic growth, reduce oil imports, and have adequate supplies of natural gas for residential and small commercial customers. Accordingly, to stimulate and increase in the demand for coal and other alternatives to gas and oil, the President's plan proposes a coal conversion program consisting of tax and regulatory measures.

The national energy plan calls for increases in coal production by 1985 to more than one billion tons per year. Some projections have estimated coal consumption by the end of the year 2000 will be two billion tons per year.

The President's energy message has been received with mixed reaction by many Congressmen, as was to be expected. Representative Jack Kemp, Republican of New York, emphasized that "raising taxes on energy will not create one new barrel of oil." Representative Clarence Brown, Democrat of Ohio, complained that Carter's industrial users tax would greatly increase the price of fertilizer which would raise food prices. It will be many months yet before we know exactly how Congress will implement an energy plan.

2. HISTORY

Coal gasification is indeed America's "Ace in the Hole." The National Coal Association, which came up with this slogan also reminds us that there is "no fuel like an old fuel." There can be no denying that good old coal looms large in our country's energy future, just as it did in our past.

It is important for us to remember that coal gasification is not a new concept. The gas industry actually grew up using coal as its basic raw material. Gas was first derived from coal nearly 300 years ago. As recently as the 1950's, many American gas utilities, including many here in Illinois, still manufactured part of their supply from coal. Today, the industry talks of first and second generation processes for coal conversion; "first" being commercially proven technology, with "second" referring to processes in the research and development stage with the potential for lower capital cost, higher thermal efficiency and ability to more effectively utilize high sulfur and caking coals such as those that are so abundant in Illinois.

3. GAS SUPPLY

Proven domestic natural gas reserves in 1976 again declined for the eighth time in nine years, from 228 trillion cubic feet at the end of 1975 to an estimated 216 trillion cubic feet at the end of last year, according to the American Gas Association's Committee on natural gas reserves. Proven reserves, as defined for the purpose of the AGA report, are those reserves of natural gas known to exist which can be produced economically using conventional methods.

The American Petroleum Institute reported last month that the number of gas wells drilled in 1976 increased, but since the price has been held so low, 90% of the activities were in low cost drilling areas where only 30% of the potential undiscovered gas resources are thought to be.

Dr. William McCormick, Jr., AGA Vice President of Planning and Analysis, pointed out that today's residential user pays half as much for gas as he would for oil, and only one-fifth as much as he would need to pay for electricity. Little wonder, that at an average wellhead price of $0.60/MCF or an equivalent of $3.60 a barrel of oil, U.S. gas production has declined. On conventional supplies, McCormick said that "Gas reserve additions have continued to decline largely because the drilling is in older, less risky, and in less costly areas -- generally onshore and at shallow to moderate well depths." With new gas deregulation, he predicted "that gas production in the lower 48 states can be leveled out at about 20 trillion cubic feet into the early 1990's." But as of today, gas deregulation has still not come about.

The Federal Power Commission said just last week that natural gas shortages may be worse this coming winter than they were during the winter of 1976-1977. An FPC report based on gas companies projections estimated the interstate pipelines will have 169.9 billion cubic feet less gas available for delivery during the 1977-1978 season than they did last year. The estimate means shortages could conceivably be worse in the coming winter than during the last one, even if the winter is normal.

As any American who was not isolated on some desert island last winter knows, it was a record cold winter for the upper midwest and east. This record weather, coupled with already curtailed supplies from the pipeline companies put a severe strain on the gas distributors in Illinois. For many companies, high peak day sendouts quickly depleted gas held in storage and alternate sources of gas.

Weather data indicates January 1977 was our coldest in two centuries. However, the utilities in Illinois, with many years of careful planning and substantial supply investments, were able to handle last winter's gas shortage better than others. This success was due to investments in vast underground aquifer storage systems, investments in supplemental natural gas plants which converted liquid hydrocarbons to distribution gas and investments in off-shore gas explorations. My own company, Northern Illinois Gas Company, was able to divert emergency supplies to eleven other companies to satisfy priority needs. So all these investments were important not only to gas customers in Illinois, but to residential consumers ranging from Omaha, Nebraska to Brooklyn and from Minneapolis, to Birmingham, Alabama.

As gas utilities look ahead, it is obvious that we must include coal gasification to augument the supplies of traditional pipeline gas. Gas from coal can be a far more attractive fuel than coal itself. It would be more expensive than regular natural gas - although $4.00 to $5.00 per thousand cubic feet is no more than new gas from Alaska or the outer continental shelf. Even at that price it can still heat homes for as little as half of the cost of electricity produced by traditional means. Also, when synthetic gas is burned, it doesn't foul the air the way coal does. "It can meet any standard the Environmental Protection Agency might set," says ERDA's gasification expert, Ezekial Clark. "In the future, it may be the only way to use coal satisfactorily in our environment."

4. DELAYS

With all the points in mind that were just covered, one wonders why plants aren't being built in Illinois today for coal gasification. Simply stated there are still a number of uncertainties involved.

Without getting into bureaucratic barriers, let me quickly touch on the major challenges that face a new coal gasification industry. Most of the problems will be resolved, or at least clarified if we can just get the "first plant" built.

Any complex project brings with it concern for the environment. A 1975 study conducted for the FEA determined that the environmental impact on air quality for a coal gasification plant could be significantly less than for an equivalent coal fired electric plant. But this actual impact would not be known until the first plant is built.

Money is probably the most serious problem facing coal gasification. Money lenders are reluctant to finance a debt portion of the capital required unless they can be assured the loans will be paid in full regardless of the outcome of the project. This is understandable when project costs equal or exceed the value of the sponsoring firms assets and provide only a fraction of its annual supply requirements. Government involvement is required at least for the first plants, to share the financial risks with company shareholders and customers. This aid could take the form of favorable regulatory treatment, direct grants, or loan guarantees.

Another problem area in coal gasification is socio-economic. Some sections of the nation, most notably in the west openly reject coal gasification because of real or imagined threats that it may have on established lifestyles. Since most coal gasification facilities are envisioned for rural areas, the spector of urbanization and its inherent problems is one of genuine concern.

In a recent meeting in Chicago, Governor Thompson of Illinois said that until a national energy policy is firmly established, the states are limited in actions they can take. Thompson said, "We need a national energy policy that will apply to all 50 states, taking into account the regional and demographic differences." Governor Thompson says he supports greater reliance on coal and nuclear energy, but noted that difficulties will arise in achieving both energy and environmental goals. For instance, strip mining laws that ignore differences between western and midwestern states will impair the nation's ability to use coal.

5. WATER

A major challenge to coal gasification is water, because large quantities are required. Illinois is fortunate to have the Mississippi River, the Illinois River, and lakes from which to draw water. This difference sets Illinois apart from the western states where there are large reserves of coal but water is not so abundant. Coal gas could be produced in the west and could be efficiently transported to midwestern markets. However, there is a reluctance to export water via coal gasification. This reluctance can only be overcome in the west, if local, domestic, municipal, industrial and irrigation demands could also be met.

6. COAL

Illinois has the largest reported resources of bituminous coal of any state. Of great concern for the remainder of this century are those resources classified as recoverable reserves calculated on the basis of their being technically, legally, and economically mineable under present conditions. Recoverable reserves of bituminous coal in Illinois have been estimated to total nearly 33 billion tons. At the present rate, that amounts to over 600 years of mining.

Ten to fifteen percent of recoverable reserves in Illinois may be technically recoverable by surface mining and the remainder must be recovered by underground mining.

A new report from the Illinois Stage Geological Survey indicates that the demand for Illinois coal is finally increasing after a decade of stagnation and decline. The report predicts that in 1985, the State's coal industry may need to supply 93 million tons annually, 55% more than the 60 million tons it produced in 1975.

Consumption of Illinois coal by utilities will account for much of this increase. The utilities increase will be almost 50% over the next eight years according to a report released by the Environmental Protection Agency.

Even though new regulations and environmental difficulties have seriously delayed the construction of nuclear generating plants, and in spite of existance of coal practically under the plant, Illinois utilities are still building nuclear plants. Projections for additions and new sites in Illinois represent a growth of about 60,000 megawatts between 1976 and 1990. The new capacity is roughly 50% nuclear and the remainder fossil fuel.

7. MINING PROBLEMS AND SOLUTIONS

Mining regulations are at long last apparently reaching a point where all parties will know what is to be expected. The Federal Surface Mining Control and Reclamation Act of 1977 is expected to be passed into law reasonably soon. At the present time, it appears that there will be a five year moratorium on prime agricultural land as an amendment to the bill. In anticipation of the Strip Mine Bill's passage, the Interior Department has begun work to establish new offices for administration. However, no State reclamation funds will be granted until a State's full regulatory program is approved by the Department of Interior. The aim here is to encourage strong State regulatory programs.

Illinois has moved forward on mining regulations and Mr. Russell T. Dawe, Director of the Illinois Department of Mines and Minerals, announced recently that three mines covering 160 acres in two Illinois counties will be the first sites for reclamation under the State's new Abandoned Mine Land's Reclamation Act of 1975. The Abandoned Mine Land Reclamation Council will contact municipal and county officials in the mine area to develop reclamation plans suited to community needs. Mr. Dawe stated that the selection of these three mines is the first step in a major effort to reclaim abandoned mines in Illinois by returning them to productive use while at the same time eliminating the environmental hazards.

As another progressive measure, the Bureau of Mines of the Illinois Geological Society, Illinois Department of Mines and the University of Illinois are working on a project to develop antisubsidences and mine backfilling techniques in long abandoned coal mines in southern Illinois.

8. COAL GASIFICATION PROJECTS IN ILLINOIS

Here in Illinois a number of major steps have been taken in a forward direction toward coal gasification. These activities involve the Federal Government, the utilities within the State of Illinois, both gas and electric, and the Institute of Gas Technology.

The Institute of Gas Technology has been awarded by ERDA, two major contracts for coal gasification work. The larger contract for $9,282,000 covers the operation of a pilot plant to develop the steam iron process. This process reacts char with steam, air and a continuously regenerated stream of commercial iron ore to produce a high purity hydrogen as part of a process to convert coal into synthetic gas and oil.

Under a second contract awarded by ERDA for $8,230,000, IGT will complete the operation of the HYGAS plant over a twelve month period. The plant has experienced successful runs in converting lignite and bituminous coals to a high btu pipeline quality gas. Just last week, the HYGAS plant completed another long self-sustaining run using high sulfur Illinois agglomerating coals.

In the utility area, ERDA and the Commonwealth Edison Company have signed a letter contract for a coal to gas combined cycle system in Illinois. The first $1.8 million has been committed for the coal gasification facility to be built near Pekin, according to Thomas G. Ayers, Commonwealth Edison Chairman and President. Commonwealth Research Corporation, a wholly owned Edison subsidiary, has signed a letter contract with Energy Research and Development Administration to allow preliminary engineering and equipment procurement while the two parties negotiate the final terms of the contract.

The installation will combine a Lurgi gasification system with a purification process to remove 90% of the coal's sulfur. The system will be designed to convert about 20 tons of coal per hour to a clean, low btu gas suitable for use as a fuel in a gas turbine driven generator capable of producing up to 25,000 kilowatts of electricity. Total project cost previously had been estimated at $167 million.

The Illinois Coal Gasification Group has taken a tremendous stride forward in the coal gasification area with its ERDA project. The group consists of five utilities within the State. Three are gas utilities and two are combination gas and electric distribution companies. The group has been awarded a $22.5 million contract for the initial design phase which could lead to construction of a coal gasification demonstration plant in southern Illinois. The project will be funded in three stages as work progresses. The first phase, extending over 21 months, involves conceptual development and engineering design. With joint approval by ERDA and the ICGG, the project would proceed into construction and operation. The plant would be designed to process 2,200 tons of high sulfur coal per day and would produce about 18 million cubic feet of gas and 2,400 barrels of synthetic crude oil daily. Byproducts from the plant are sulfur and ammonia which will be sold for commercial uses.

If a site contract is successfully negotiated, the demonstration plant would be situated on 350 acres in Perry County, west of Pinckneyville in southern Illinois. The proposed site is approximately 65 miles southeast of St. Louis, Missouri. The total cost of the project would be approximately $334 million. Those dollars are expressed in 1977 dollars.

You can readily see from the foregoing that the utility companies in Illinois, both gas and electric, are ready to make their move into coal gasification projects. These present demonstration efforts will provide the basis for commercial plants in the future.

9. RELATIONSHIP OF ALL THIS TO SYMPOSIUM ON INSTRUMENTATION AND CONTROLS

As we have moved into the preliminary engineering work in our ICGG project, and I'm sure that Edison and IGT have found the same thing, there is a tremendous challenge for people who are involved with instrumentation and control. It is absolutely essential that we are able to measure all the variables in these new coal gasification processes.

Control equipment and systems will be a major element in the design of commercial scale coal gasification plants. As we project into the future, process computer control will be as common in coal gasification plants as pneumatic and electronic controls are in today's chemical plants. Therefore, this general concept of process computer control must be integrated into the development of new systems designed for the use of coal conversion industry.

Coal gasification plants, as it is with other process plants, are composed of a series of unique operations combined to form an overall process. One of the key areas in the success of any coal gasification project will be the ability to move, in a controlled manner, run of mine coal through several operations and be properly sized to enter a gasifier at elevated temperature and pressure. We feel that it is in this area of solids movement that the need for improved instrumentation is the greatest. This problem was highlighted during several discussions at the recent conference on coal feeding systems held at the California Institute of Technology.

The gas industry and the electric industry in Illinois have always relied heavily on automation in all their plants. These are plants for conversion of coal to electricity, nuclear sources to electricity, liquid hydrocarbons to gas, and gas storage and pumping operations. As a continuation of this capital intensive approach to business the industry will continue to look toward au-automation and computerized controls. The utility industry must serve its customers in rain, sleet, hail or snow. Whatever the conditions, the energy must continue to flow to the customers, and

this can only be done through proper control systems. Therefore, there is a challenge to all of you in the industry of instrumentation and control to provide the expertise for those of us in the energy business in Illinois so that we may meet the demands of our customers.

Thank you for inviting me here this evening. Its been a great pleasure to participate in the symposium. Thank you.

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PROCESS STREAM MEASUREMENT SESSION - DILUTE PHASE

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COAL FEEDING AND PNEUMATIC TRANSPORT

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COAL FEEDING AND PNEUMATIC TRANSPORT

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INTRODUCTION

Since 1967 Combustion Power Company has been engaged in the development of a Solid Fuel Gas Turbine energy conversion system using a pressurized fluidized bed-combustion process. The primary test facility, located at Menlo Park, California, is a 1MW Process Development Unit (PDU) that was constructed for EPA in 1973 for the conversion of municipal solid waste to electrical power. From 1973 through 1975, the PDU (originally named the CPU-400 Pilot Plant) was used by the Office of Coal Research/ERDA to evaluate the energy conversion of high-sulfur coal using CPU-400 technology. The PDU was operated under test conditions for 592 hours using Illinois #6 coal (4% sulfur) as fuel and a western dolomite as sorbent. The uninterrupted test periods ranged from a few minutes to 30 hours each. These short test periods were due primarily to equipment malfunctions, 60% of which involved the coal-feed system. Follow-on sections of this paper describe the PDU coal-feed system and the types of problems experienced.

PROCESS DEVELOPMENT UNIT

The Process Development Unit (Figure 1), consists of a coal-processing system, a hot-gas system, a turboelectric generator system, a process-control system, and an instrumentation system. The primary flow paths for the working gas stream are shown in Figure 2. Air is drawn from atmosphere, pressurized to 4 ATM in the turbine compressor, and delivered to the outlet piping manifold; air-control valves direct the air so that any part of it can flow through the fluid-bed combustor, while the rest is bypassed through the Ruston combustor. This permits the system to be operated either on the oil-fired Ruston combustor or on the coal- or oil-fired fluid-bed combustor. In the fluid-bed combustor, the primary air stream flows up through the sand bed. Fuel is injected into the bottom of the fluidized sand bed and is largely consumed within the bed. The hot combustion products (1600 F) then flow through three successive particle-separation vessels. The cleaned hot gas expands through the turbine to drive the compressor and 1MW generator, and then exhausts to atmosphere.

Coal-Processing System

The coal-processing system, shown in Figure 3, contains that equipment necessary for reducing the coal lump size to less than 1/4 inch and moving it to storage; for moving the SO_2-suppressing additive to storage; for providing dust control while processing; for providing an inert atmosphere while in storage; and for metering and pneumatically transporting the coal and additive to the fluid-bed combustor in the correct proportions and at the correct rate.

Fuel Preparation - Initially, coal and dolomite are loaded into separate loading hoppers by a front loader. The dolomite is then moved and lifted directly into a dolomite storage silo by a series of three 6-inch screw conveyors that are enabled when the additive silo is not full; the coal is fed to a crusher before being fed to a coal-storage silo. An 8-inch trough conveyor that is controlled by the crusher-motor current and is enabled when the crusher outfeed conveyor is operating, meters the coal for the crusher. The coal crusher reduces -7/8 inch coal to -1/4 inch at a rate of 6 tph. From the crusher, the coal is moved and lifted to a coal-storage silo by a series of three 6-inch screw conveyors that are enabled when the coal-storage silo is not full.

Coal and Additive Storage - The two storage silos provide a 24-hour supply of coal and additive and are each equipped with a gyrated bin bottom to facilitate outflow.

From the storage silos, a series of three 6-inch screw outfeed conveyors, move the coal and additive to two 110-cu-ft feed hoppers. These conveyors are enabled when the feed hoppers are low and are disabled when the hoppers are full. Both the feed hoppers are also equipped with gyrated bin bottoms which are activated only when the outfeed surge box becomes empty. From the feed-hopper surge boxes, the coal and dolomite are metered onto two weigh feeders.

Twelve level-indicating controls are employed in the coal and additive containers to supervise conveyor and bin-bottom action. These devices, Roto-Bin-Dicators, are slow-speed synchronous motors which stall when in contact with the process media to complete the control circuit.

Weigh Feeders - Two K-Tron Weigh Feeders, Model GF-1212, are employed to meter and ratio the coal and additive as dictated by the feed-control system, Figure 4. The feeders receive a feed-rate setpoint from the control system and adjust the belt speed to satisfy the requirement. Digital weigh circuitry is employed in order to improve accuracy and an error memory accumulates any disparity from the setpoint error. A linear-voltage differential-transformer load cell is used in the weigh system which, when combined with belt speed, provides a digital readout of the feed rate, the total weight fed, and the feeder setpoint on a local panel, plus an analog feed-rate signal back to the control system.

Airlock Feeder and Transport - An airlock feeder valve receives the coal and additive at ambient pressure from the screw feeder and transfers it into the pneumatic-transport line. The valve is an ESCO 12-inch Rotofeeder. It is of stainless-steel construction, designed for 150-psi operation, and driven at 11.7 rpm by a 7.5-hp motor through a 150-to-1 gear reduction. From the airlock-feeder valve, approximately 50 lb/min of coal and additive drop into a 1 1/2-inch schedule 40 transport pipe where 21.3 lb/min of compressed air moves the fuel 300 feet and into the fluid-bed combustor, as shown in Figure 5. The air compressor which provides the transport air also provides air for instrumentation, baghouse cleaning and shop service. For the latter, it works in parallel with another compressor.

A process-control valve regulates the velocity in the transport line to the 50 fps required to transport the 1/4-inch coal particles through 400 feet

of piping, which includes four 90-degree turns, to the fluid-bed combustor. A feedline isolation valve is located near the combustor and is programmed to close should an unsafe condition exist.

Dust Safety System - Since the dust from coal processing creates a potential health and safety hazard, a dust-collecting unit and an inert-gas purge system are included in the facility. Dust collection of coal and additive is made in the area of the crusher and the airlock feeder. The dust (about 6% by weight of the total feed) is pneumatically injected into the feed transport line downstream of the feeder valve through a double valve and timing-sequence system. The general arrangement is shown in Figure 5.

FEED SYSTEM PERFORMANCE

During the 592 hours of coal combustion tests in the PDU, there were 141 test interruptions due to coal-feed system problems broken down as follows:

Feedline Erosion	12
Feedline Plugging	47
Feeder Valve Malfunctions	78
Feed Control System Malfunction	4

Feedline Erosion - The possibility of an erosion problem in the pneumatic-transport line carrying the fuel to the combustor was recognized in the original design of the feed system--but its magnitude was not. Originally, all directional changes were accommodated with bends of 48-inch radius. These failed by erosion after little more than four hours of operation. For transporting some solids, bends of reinforced rubber hose have seen successful use; their life span before failure in transporting coal and dolomite, however, was on the order of five minutes.

A design of specially configured steel piping had also seen success in transporting erosive solids, and that was next installed at critical points. It incorporated a series of "dead boxes" designed to retain some of the transported material, thus serving as an expendable impacting surface (Figure 6a). This was somewhat more successful than the simple curved pipe, but still wore through at the junction between adjacent pockets.

The design solution finally adopted employed right angle turns using dead-ended tees. One arm of the tee, being capped, provided a reservoir of material to absorb impact (Figure 6b). Transport-line failure ceased to be a problem after this final modification.

Feedline Plugging

Upon satisfactory resolution of the feedline erosion problem, another feedline problem appeared. Tramp material, such as pieces of wire and wood which were less 1/4" in one dimension, but over 1 1/2" in length would enter the 1 1/2" feedline and create a plug. In one test sequence of 80 hours, there were 10 interruptions from this cause. When a plug occurs, it is difficult to find the exact location. Removing the plug takes several minutes which usually necessitates a plant shutdown.

A simple mechanical "fix" resolved this problem. The crusher output was

screened, and only that material passing a 5-mesh screen entered the coal silo. That which would not pass a 1/2-inch mesh was discarded as trash, and intermediate-size material was returned to the coal crusher. The arrangement is illustrated in Figure 7.

As a further precaution to prevent feedline malfunctions from causing total plant shutdown, a parallel feedline was installed that could be quickly substituted for the malfunctioning line.

Feeder Valve Problems

During the early test phases, feedline erosion and feedline plugging were the dominant problems. However, as the number of hours under coal combustion increased, the feeder valve became the weakest link in the system due to erosion of pressure sealing parts. The rotary airlock feeder valve used for most of the testing was of the type shown as Model A in Figure 8. Leakage paths exist at the rotor end plates and the shaft bearing surfaces. Fine particles of the coal and dolomite mixture caused erosion at these surfaces which accelerated the leakage and erosion to the point the feeder valve could not sustain the combustor requirements. On several occasions, the high leakage overloaded the coal dust vent system. A major overhaul of the valve was required after less than 200 hours of testing.

Several versions of an expansion-chamber device above the feeder valve were experimented with to reduce the apparent air velocities above the feeder valve, but leakage and dust problems persisted. Attention was then focused on the adapter beneath the feeder valve, and its interface with the pneumatic-transport air. A substantial portion of the transport air was being diverted up through the clearances, tending to fluidize the fines in the incoming solids, as depicted in Figure 9.

Eventually enough fines would be suspended to cause bridging and complete stoppage of fuel feed. The transition section was, therefore, modified as shown schematically in Figure 9b, to provide for the entry of most of the transport air near the top of the adapter through four large-diameter (thus low-velocity) pipes. The major component of airflow is thus directed downward toward the outgoing transport line. This expedient ended the problem of "dust plugging". The final system configuration is shown in Figure 5.

A rotary airlock of somewhat different construction (Model B in Figure 8) was used periodically. It is readily seen that implicit in this design is a requirement for exceedingly tight clearances between drum and housing. The result was that the valve had a tendency to freeze and thus required greater torque than was available to rotate it. The characteristics was the cause of 22 interruptions of operation during one 95-hour test sequence.

Feed Control

A relatively high bandwidth system for control of turbine inlet temperature uses bypass air modulation whereas bed temperature control is relatively low bandwidth as dictated by the high thermal capacitance of the fluidized bed.

Plots of significant parameters during a 30-hour period of operation are

shown in Figures 10 and 11. Turbine-inlet temperature, computer controlled by modulation of a bleed flow of cool air from the compressor outlet, is seen in Figure 10 to have been held within ±4 of the 1400 F setpoint whereas bed temperature was held to ±10 of the 1600 F setpoint except for the momentary coal feed upset. The periodic dips in SO_2 concentration, seen in Figure 11, correspond with periods when the coal hopper at the point of coal and dolomite mixing nears an empty condition. During these periods, by virtue of the shape of the hopper, the coal being fed is briefly higher in fines. This coal releases heat more rapidly, and the computerized control system signals a reduction in feed in order to hold bed temperature. Note that there are corresponding dips in feed rate for both coal and dolomite, the latter being slaved to the former to maintain the specified ratio.

SUMMARY

The energy conversion process described in this paper, from coal crushing to generator output, is high amenable to computerized control as demonstrated in the 600 hours of coal-combustion tests in the 1MW PDU. The instrumentation and automatic control equipment permitted smooth transition between operational modes starting with the turbine operating on its own oil combustor and ending with steady-state operation on the coal-fired fluid-bed combustor. In continuous operation, bed temperature and turbine inlet gas temperature were maintained within ±10 F and ±4 F, respectively.

Minor, short duration, feed supply upsets had virtually no effect on power output due to the high thermal capacitance of the hot-gas system. However, the inability to feed solids reliably from ambient conditions into the pressurized combustor resulted in major feed supply upsets and caused frequent test disruptions and shutdowns due primarily to feeder valve erosion from the coal and dolomite fines.

Even though the problems of feedline erosion and plugging were solved during the PDU tests, the corrective actions of straight runs, dead ends, feedline redundancy, and screening of the crushed coal were expedients for a test program. A commercial plant feeding a similar solids mixture that is required to operate 8000 hours a year will require abrasive resistant transport piping, and expensive screening of the coal to prevent the entry of outsize foreign objects. A rugged dry-coal feeder is also required such as those under development for ERDA by Lockheed Research Laboratory, Ingersoll-Rand Research Inc., and Foster-Miller Associates.

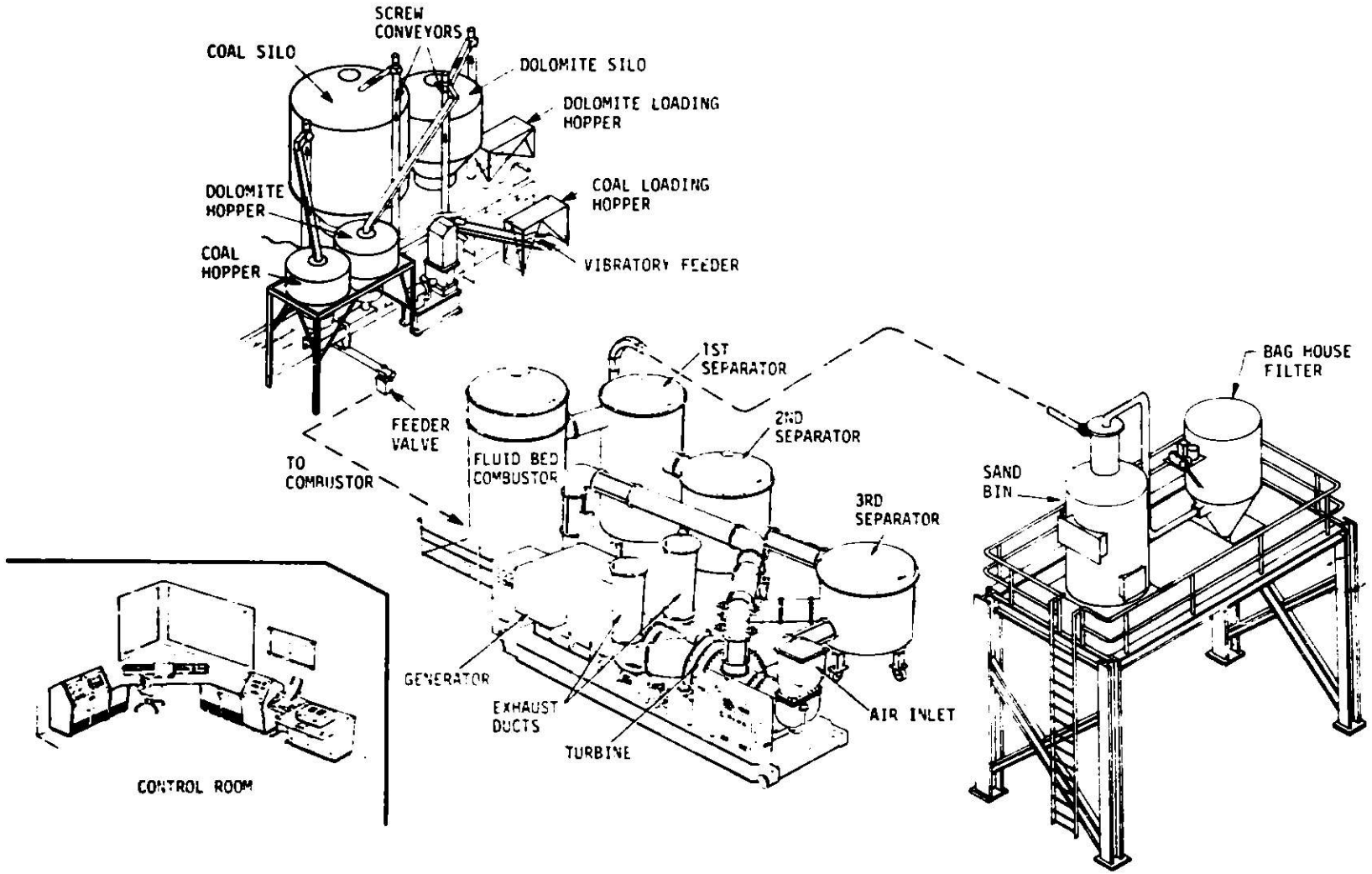


Figure 1 Process Development Unit

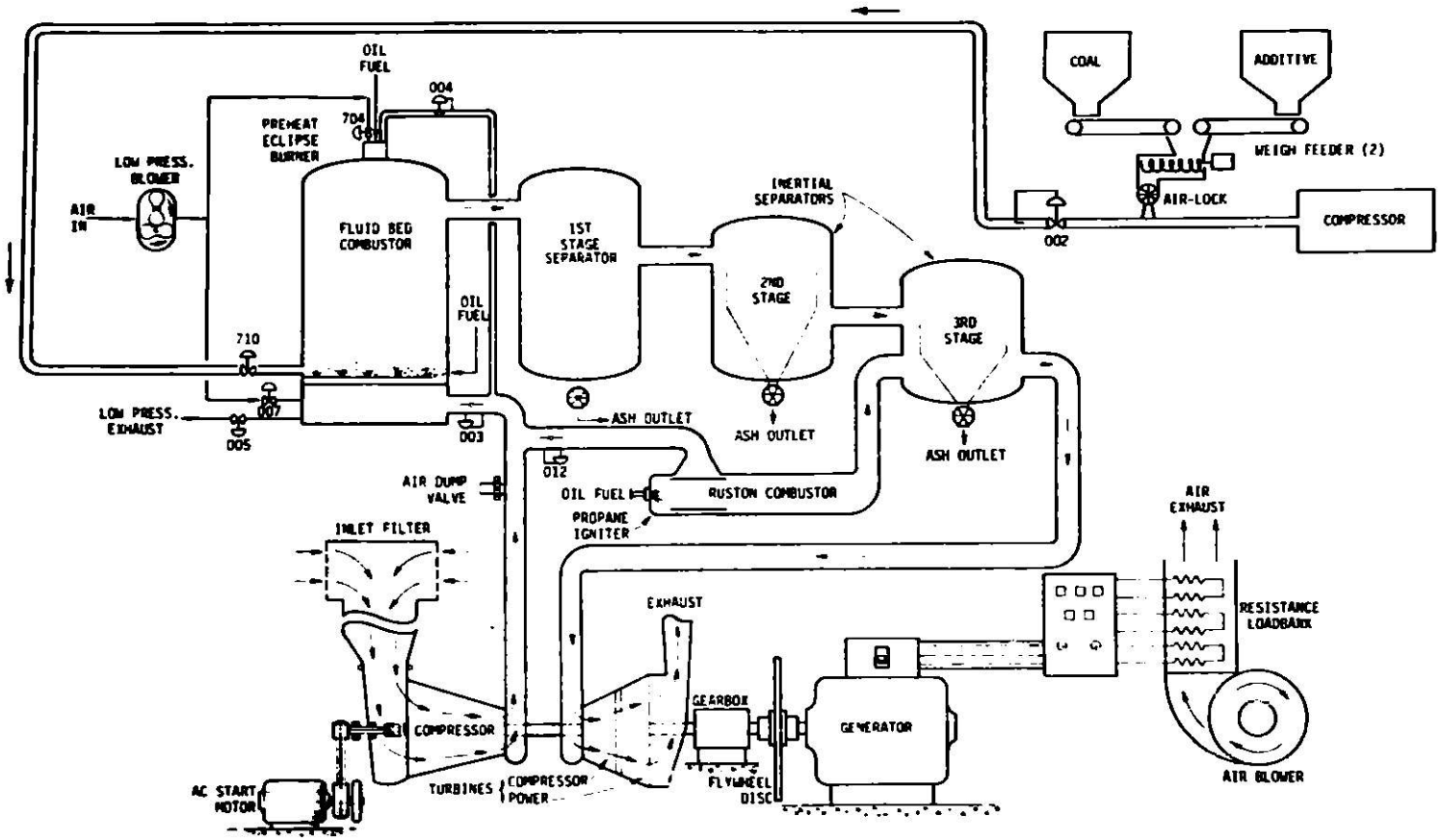


Figure 2 PDU Flow Schematic

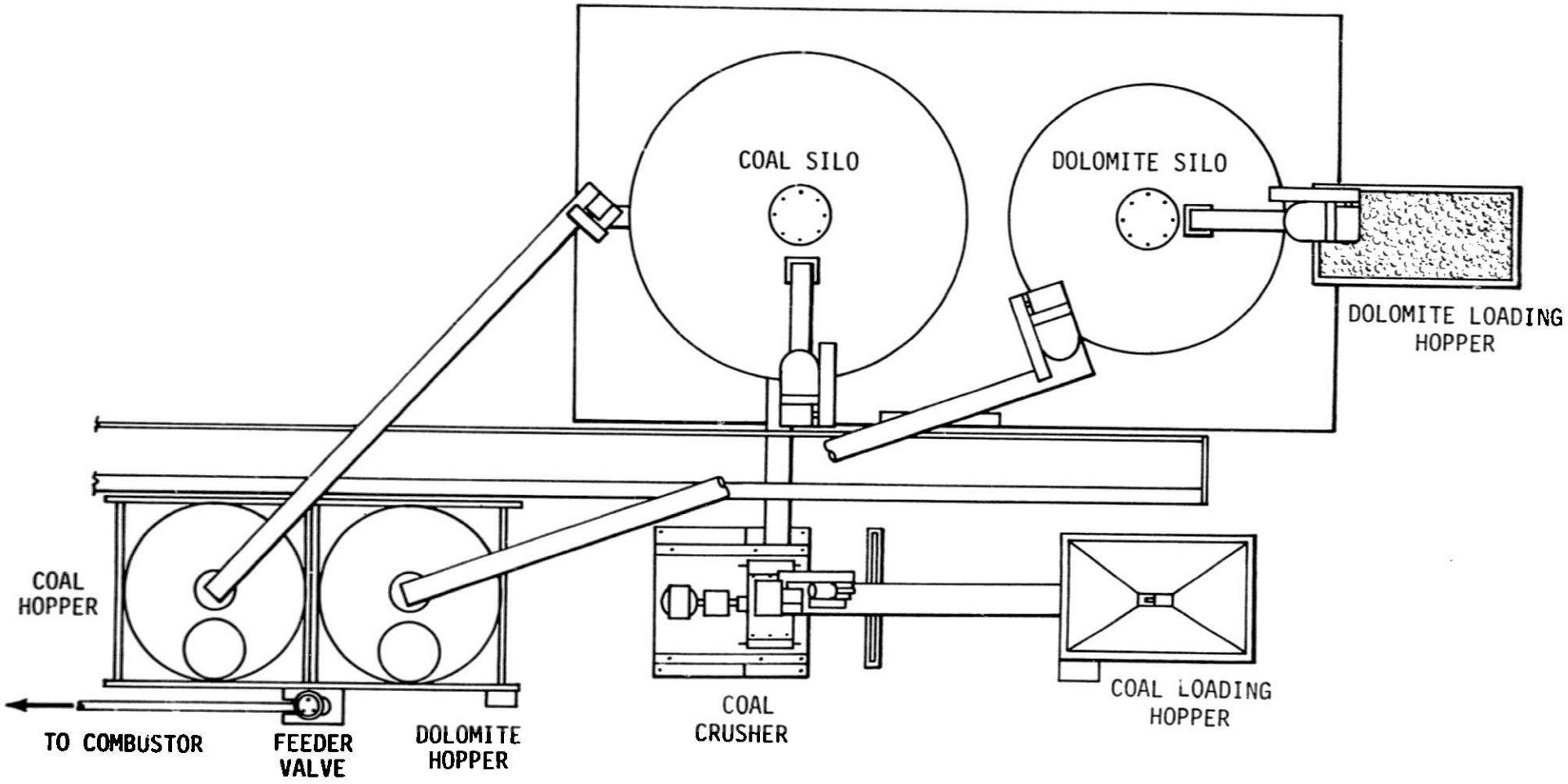


Figure 3 Coal Processing System

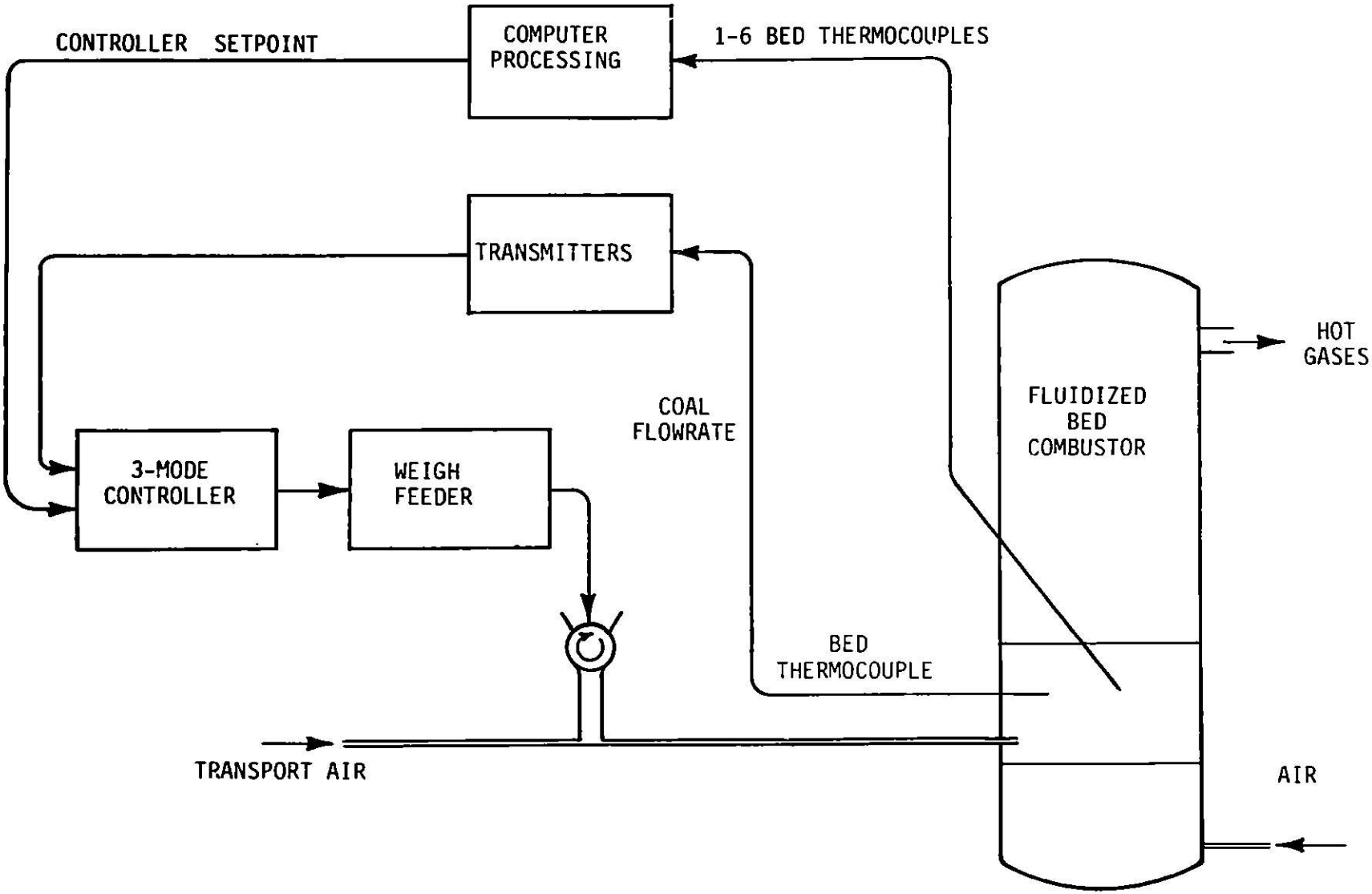


Figure 4 Feed Control System

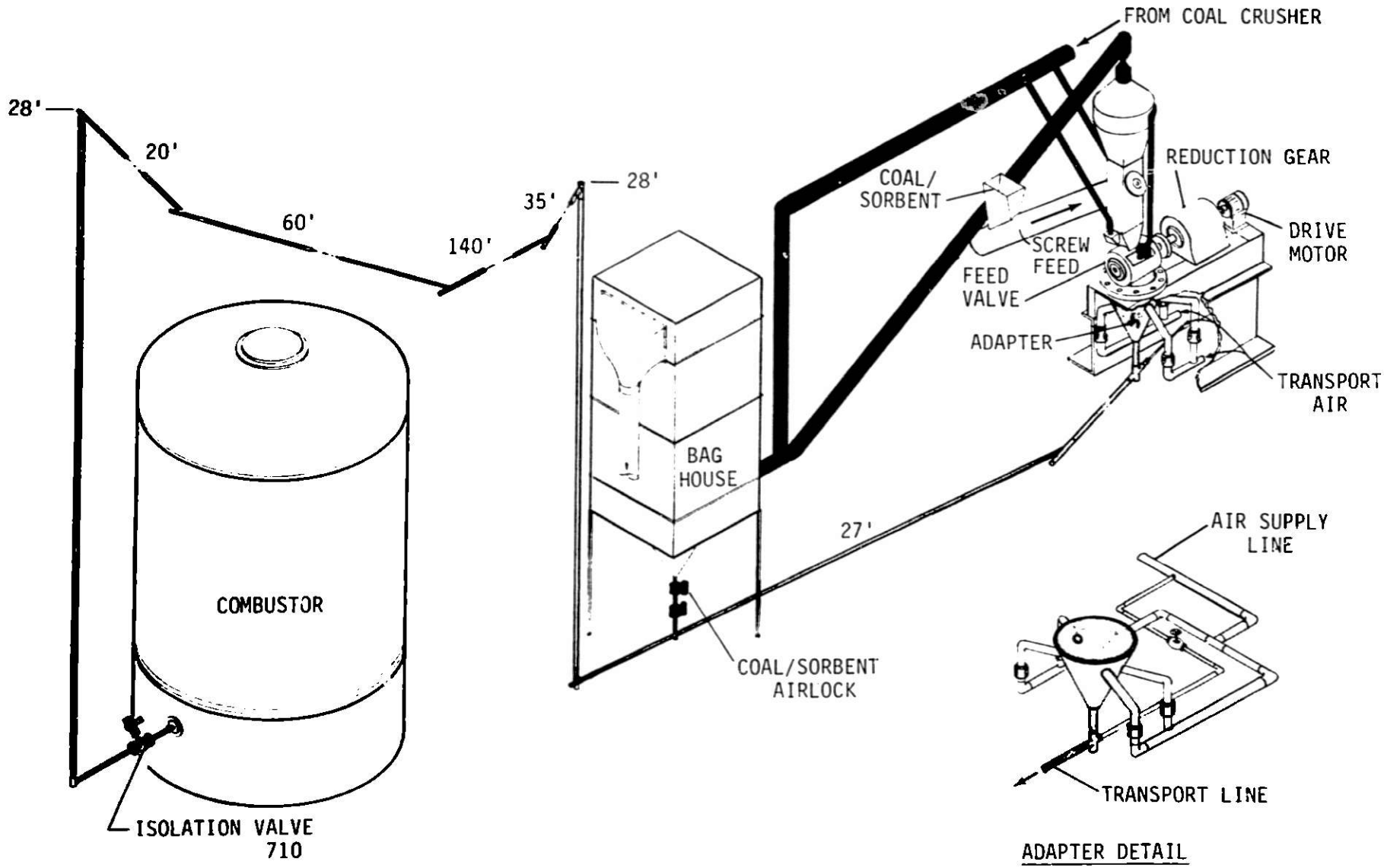


Figure 5 Coal Feed System

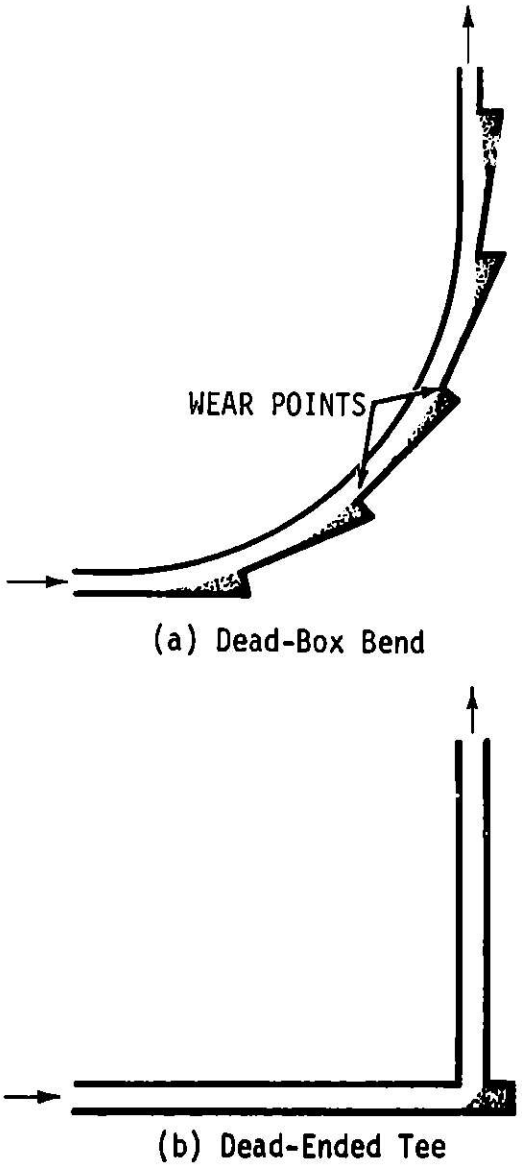


Figure 6 Directional-Change Designs for Pneumatic-Transport Line

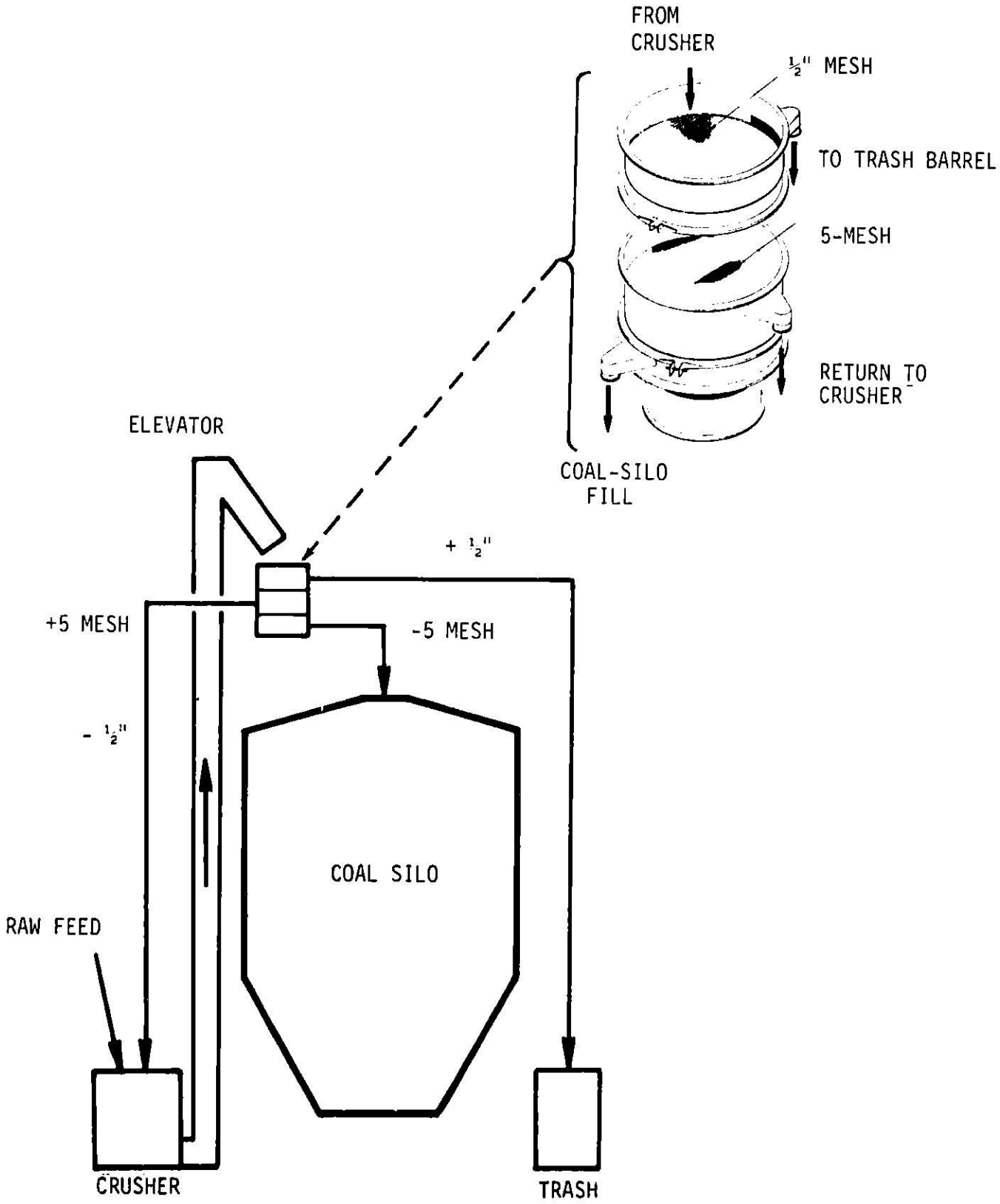


Figure 7 Feedstock Screening Arrangement

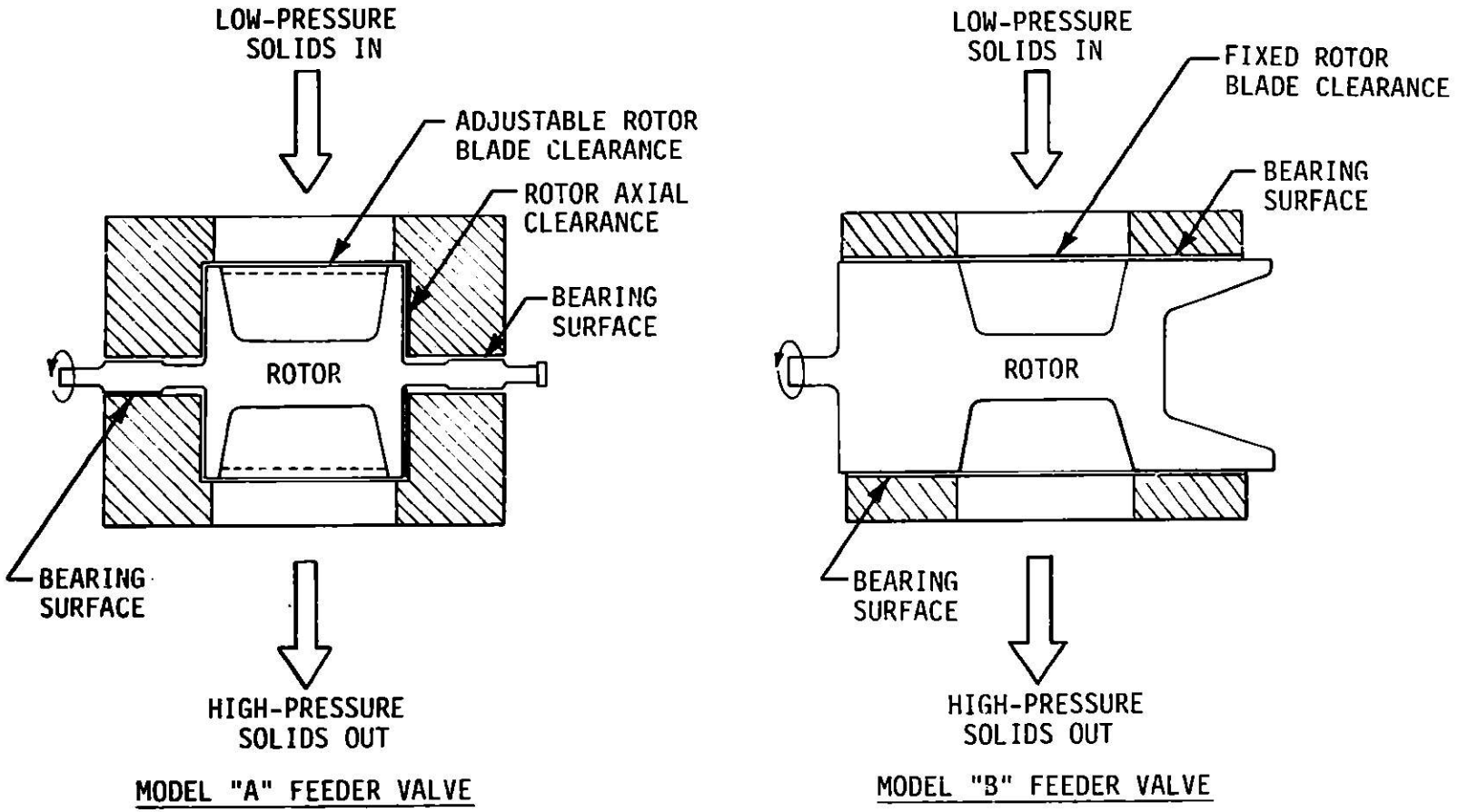
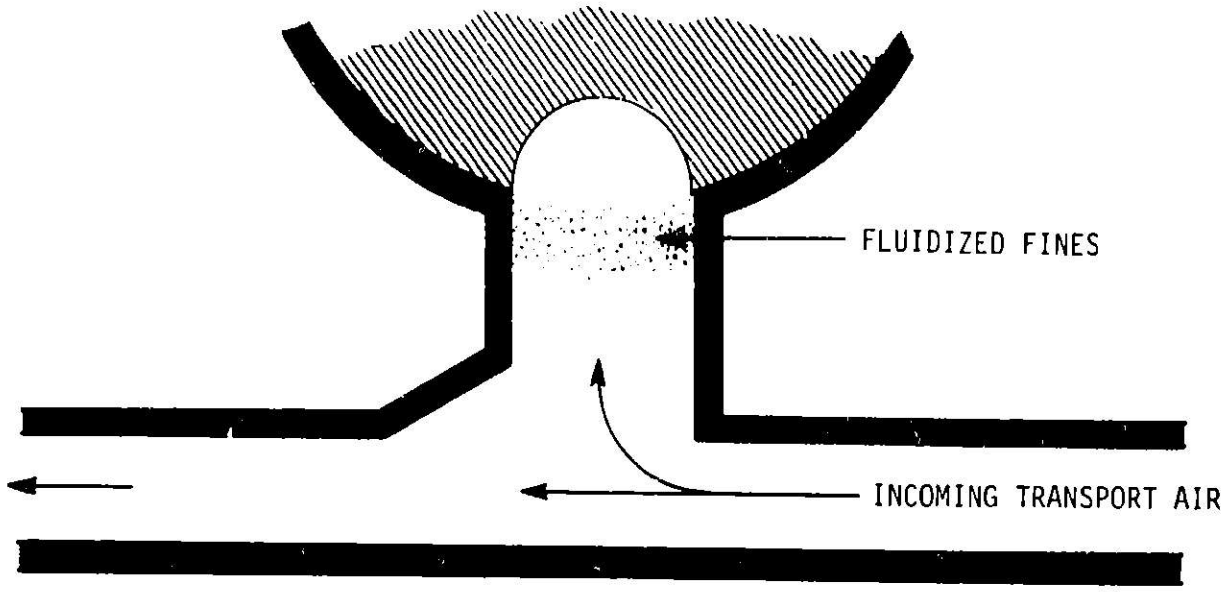
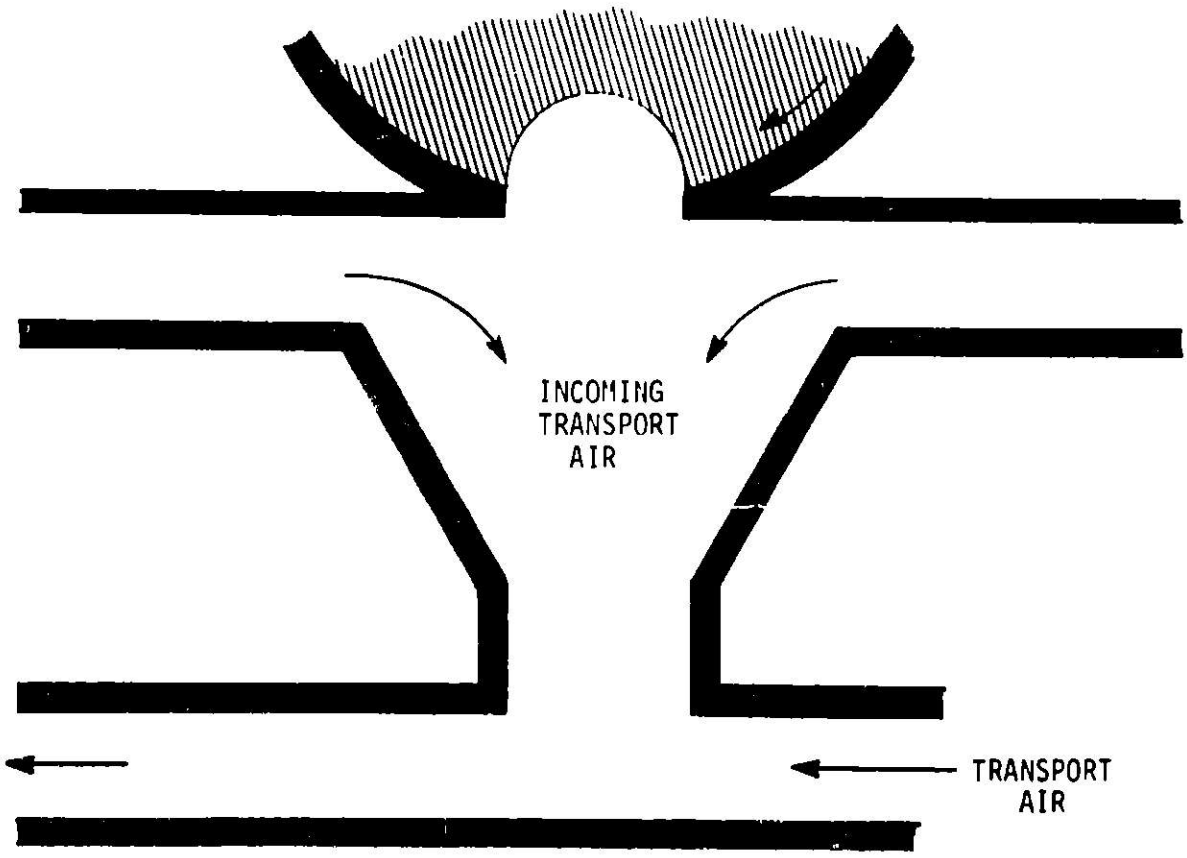


Figure 8 Schematic Comparison of Feeder-Valve Designs



a) ORIGINAL ARRANGEMENT



b) REVISED ADAPTER

Figure 9 Schematic of Revision to Feeder-Valve Adapter

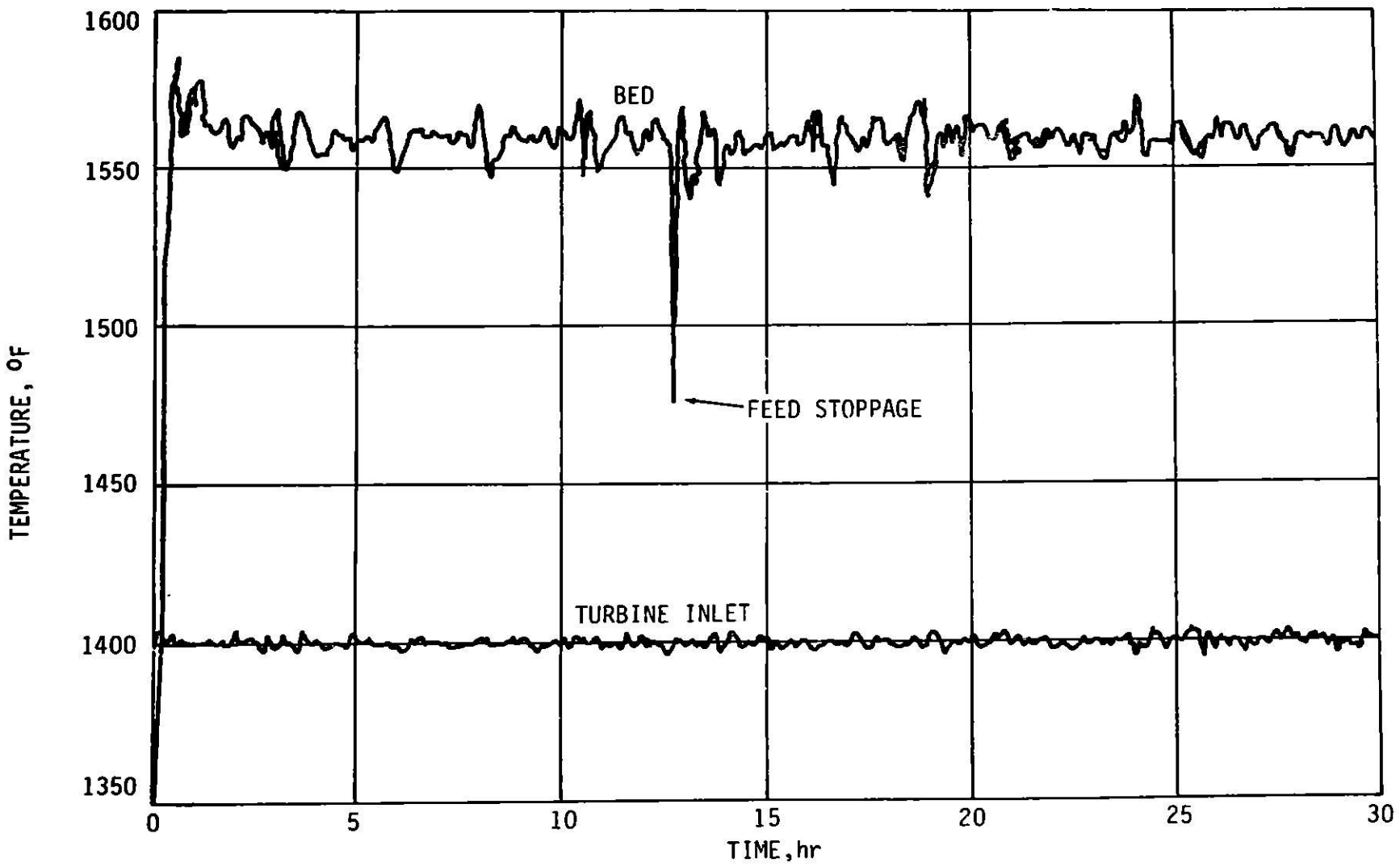


Figure 10 Control Temperatures, Test P-403A

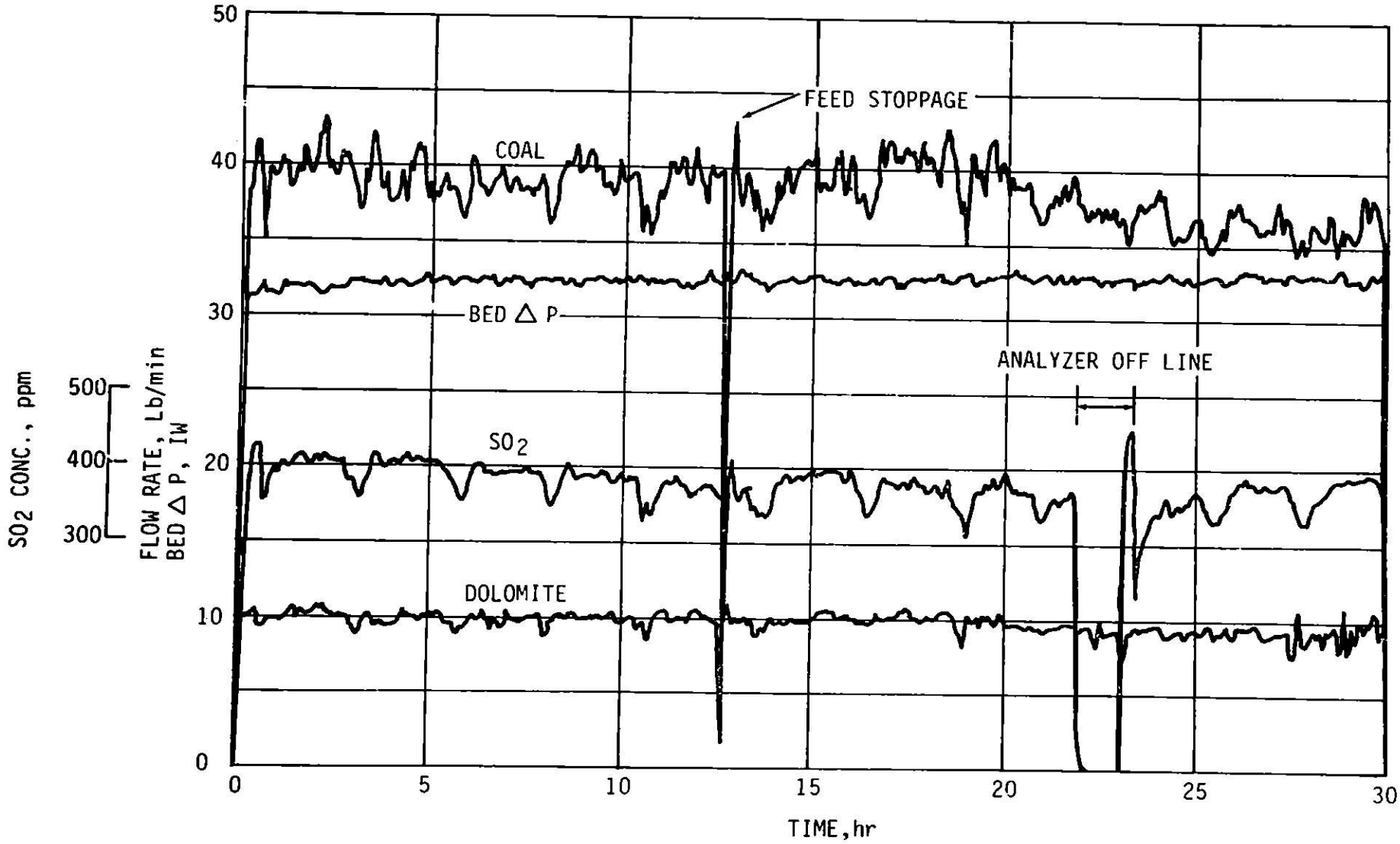


Figure 11 Feed, Bed, and SO_2 Data, Test P-403A

QUESTIONS AND ANSWERS

R. D. Smith

Combustion Power Company

B. G. Lipták, Lipták Associates

Q. What is your rangeability between minimum and maximum coal feed rate? What is the coal residence time?

A. We've operated the system with a turndown of about three to one limited at the low end by our bed fluidization criteria, which essentially would be the coal feed. The feed system can range over a much larger range than that, but the system is limited by the fluidized bed. What is the coal residence time? We can store coal in the 20 ton hopper for days at a time, the residence time in the "run" hopper is probably one hour. Once it gets through the weighing scale and the pressurized feeder valve, transport into the fluid bed only takes 6 seconds.

A. Chaudhuri, Door-Oliver, Inc.

Q. At what pressure do you operate the reactor?

A. We're operating at 60 psi, and that is determined by the pressure ratio of the compressor of the gas turbine. The excess air is roughly 250-300%. How successful is the gas cleaning? The answer to that is, poorly. The status of the program is, I might add, that for the last year and one-half and for the next year and one-half, we will be focusing entirely on the gas cleaning problem. The schematics that we showed you here showed three stages of inertial separators, which were the first attempt at gas cleaning. That was not successful at all. We were learning. We concluded that we needed much better filtration, and have been working on a moving bed granular filter to operate at 1600°F supported by ERDA.

D. F. Ciliberti, Westinghouse Research and Development

Q. What was the particulate composition, loading and size from the cleaning systems?

A. We operated the turbine with particle loadings into the breaching from three grains per dry standard cubic foot down to approximately 1/10th of a grain per dry standard cubic foot. The operation of the initial separators was not as calculated; we experienced many plugging problems, many upsets, and things of that nature. It became quite clear after the testing advanced, that we just didn't have the right solution. Nevertheless, the second part of the question, "what about erosion in the turbine?" The answer is that under these very high loadings we saw a lot of erosion, but under the lower loadings (and the majority of these are probably less than ten microns) you would get accumulations of these

materials because they are sticky at these temperatures. The accumulation would get on the walls of the scroll and then a piece of about 1/4 in. diameter would come off. That piece would go through the turbine, and cause considerable erosion. You not only get erosion however, you also get condensation of the alkaline vapors. They come through the filter as a vapor, and then as you expand the gas through the turbine, they condense on the surface of the blades. So the problem of gas cleaning is not only one of particle removal, it's also one of the chemistry of trying to react these various sodium and potassium sulfates in such a way that the vapor pressure is reduced and they can be changed to a particle and taken out as a particle. It's very complicated.

F. Bondy, Foster Wheeler Energy Corporation

Q. Were you able to measure the amount of gas blowback from the reactor through the rotary valve?

A. We don't have a quantitative number that I can quote to you, but the valve was really not very successful. We operated it only 200 hours before it had to have an absolutely major overhaul, and it was just sort of a question of time before it degraded. The elaborate duct system and all of those things that we developed were an attempt to operate with basically a degraded system. I think we feel that the rotary valve is not suited to this application. We feel that other concepts or approaches such as the ones that ERDA is developing will be superior.

Q. Who manufactures the rotary valve?

A. The answer to that ESCO, located in Portland, Oregon, who makes these for the paper industry. There are several other manufacturers as well, besides ESCO.

M. K. Shieh, Jeffrey Manufacturing

Q. What is the ratio between the coal and the (dolomite)?

A. It ranges from maybe 3:1 to 4:1 by weight. We have run sulfur to calcium ratios as low as 1.5, we even had one test as low as 1.1 when we used recirculation.

F. M. Shofner, Shofner Engineering

Q. What is the mass concentration at the inlet to the turbine? Mas medium diameter?

A. I think we talked about that before. Most of these particles are very, very fine because of the initial separation tending to break them up.

Q. What is your experience with turbine erosion and fouling?

A. We talked about that before. We feel that to solve the problem of making a turbine run successfully, the grain loading should certainly be below 0.01, it should certainly be less than two microns to get rid of any physical erosion effect, and the vapor pressures of these

alkali sulfates is going to have to be below some threshold, and I don't believe we know what that is at the present time. We are quite hopeful that the granular filter that we're working in conjunction with the use of additives into the combustor would provide that answer.

ON-LINE MONITORING OF PARTICULATES

J. D. Trolinger
Spectron Development Laboratories, Inc.
Costa Mesa, California

ON LINE MONITORING OF PARTICULATES

James D. Trolinger and Chris W. Busch
Spectron Development Laboratories, Inc.

1. INTRODUCTION

Particle diagnostic instruments fall into a wide variety of categories. Some require capture sampling while others do not. Some measure parameters related to individual particles while others measure mean properties of ensembles. Some are active while others are passive. Many applications place such a broad range of requirements on the instrument that more than one method is needed.

In a recent survey we compiled and studied over 500 publications dealing with methods for particle field diagnostics, illustrating the intense interest in particle measurements. A wide variety of these methods are used in commercially available instruments. At this stage we are convinced that no standard commercially available instrument (including those we produce) can meet all of the particle diagnostic requirements of fossil energy demonstration plants. Nevertheless, we believe that the existing methods can, with proper modification, refinement, and calibration, be used to satisfy most of these requirements.

Particle diagnostic instruments of almost any variety have the following elements: a probing element which comprises a sensing element and a transmitter element (for active instruments), a storage element, a data processing element, and a display element. The concept chosen defines the probing element while the remaining elements can be somewhat similar for any of the techniques.

In fact, the probing element is typically the simplest, least expensive, and is always the most questionable part of the instrument. It produces the measured parameters for the individual particle or collection of particles. The storage element must be capable of storing this information at a rapid rate in easily retrievable form. The data processing element must put the stored data into useful form and the display makes it accessible. These latter three functions in modern technology are conducted with some form of microprocessor. They are a product of the more precise information sciences and are not directly related to particle diagnostics. They are defined by the ultimate use of the raw data produced by the probing element.

The two problem areas represented by the probing element and in the information handling part of the instrument are best considered separately, since no amount of information processing can effectively compensate for a faulty concept at the probing head.

In this paper, we discuss the factors which should be considered in choosing a particle diagnostic concept. A summary of existing particle diagnostic methods is presented. Special emphasis is given to optical techniques which can be considered as in situ methods which do not require capture sampling. Finally, an example application of a particle sizing laser interferometer is described wherein an instrument was used in the Argonne National Laboratories (ANL) fluidized bed combustor system. This application essentially proved the tractibility of such a system to a practicle problem in particle diagnostics.

2. A SUMMARY OF PARTICLE DIAGNOSTIC METHODS

The development of a particle diagnostic instrument entails four major problem areas: (1) choice and development of the probing head, (2) calibration and verification of the technique, (3) information processing, and (4) packaging. The development of an instrument should be conducted in the same order. The problem under consideration here (diagnostics in fossil fuel plants) lies in one of the more difficult classes of particle diagnostics problems. The size range includes the small particles which are difficult to control, to observe, and to reproduce for calibration. The upper end of the size range is sufficiently large that surface and shape factors are important and the lower end falls in the range of the wavelength of light commonly used, so that scattering theories cannot be expected to accurately describe the whole range with a single model.

The number density requirement is sometimes high making it difficult to examine individual particles. These are moving at a rather large velocity, meaning that particle incidence rate can be high.

The environment can be extremely harsh and places a number of difficult restrictions on the instrument.

In situ instruments are almost always more difficult to produce, as are portable, field ready instruments; however such devices have been employed under almost every conceivable condition: in freezing conditions at remote weather observatories, in hot desert environments, in airborne tests at high altitude, in furnaces, and even inside explosive clouds.

In this section we summarize the various methods currently in use.

There are many methods currently available for measuring size distributions of particulates in a gaseous stream. Although large in number, the techniques each have their own advantages and disadvantages for a given application and must be carefully selected. For example, some techniques require withdrawing a sample out of the stream and analyzing it in a laboratory while others allow direct in situ measurement. In situ devices typically allow for quick turnaround time, but the quality of data in many cases can come under question. Direct sampling eliminates many questions as far as data interpretation goes, but introduces problems with sample collection and requires extensive lab work to interpret the data.

Most devices are best suited for a definite range of particle size. For example, diffusion batteries can measure particle sizes in the 0.001-0.5 μm range while mechanical sieving is appropriate for particles larger than an ideal minimum of about 2 μm. When an in situ device is required, many methods can be eliminated as unsuitable. Nevertheless, a brief summary of available devices is informative to gain an understanding of the techniques available to qualify the ultimate in situ device.

Basically, most particle sizing techniques fall into one of the following categories:

- Optical
    - Imaging
    - Light Scattering
- Aerodynamic
    - Impaction
    - Centrifugal
    - Sedimentation (Gravitational)
- Filtration
    - Barrier
    - Sieving
- Electrostatic
- Condensation
- Diffusion
- Acoustic

The following paragraphs discuss each of these techniques.

Optical

Optical particle diagnostic methods fall into two classes, one in which the measurements are made on images of particles and a second in which

measurements are made on the field of scattered electromagnetic radiation produced by the illuminated particles.

Imaging methods include electro/video recording, microphotography, holography, and shadow spectrometry. Imaging devices must employ electromagnetic radiation of wavelength considerably smaller than the smallest size of particle under study. To date, field portable instrumentation based on imaging methods have been limited to larger particle size ranges (above 10 micrometers).

Particles scatter light according to size, shape, refractive index, polarization properties and wavelength of light. The rather complicated scattering laws combined with the difficulty in measuring absolute intensity of light in the low intensity range causes most scattering instruments to require calibration with a known size distribution -- a task which is itself complicated and subject to criticism. To be sure, the source of calibrating particles for some instruments must comprise the same material and particle shape as that to be measured. If the material is not the same, refractive index corrections must be made.

A wide range of schemes is used. The light source is an incoherent source in some, a laser in others. Measurements at more than one wavelength or more than one angle are employed to factor out refractive index dependence. Measurements may be forward or backscatter, and pulsed or continuous light sources may be employed. Finally, the measurement may be based upon scattering by a single particle or a collection of particles. These combinations lead to a near-endless array of scattering instruments.

The measured quantity is either absolute intensity of scattered light into some collecting angle, or ratios of intensity. This, combined with the knowledge of incident wavelength and intensity, particle shape and material and a proper choice of scattering theory, provides, in the single scattering case, the necessary information to compute scattering cross-section. For spherical particles, this is easy to relate to particle diameter. This method can be expected to be reliable in the study of aerosols. Measurement of the angular distribution of scattered light can also be used to determine the particle size for spheres.

The measured quantity is the same in scattering from collections of particles, but one must know in addition what type of size distribution exists and how many particles are illuminated to compute mean particle

cross-section or to know the mean cross-section and type of distribution to determine number.

Other measurements, such as scattering at different wavelength, directions and polarization, have been attempted to reduce the amount of a priori knowledge required.

Measurement of polarization changes caused by scattered light provides limited information about a particle field.

Measurement of the amount of light removed from a beam of light provides limited information about the particle field. This measurement is used primarily to determine visibility; however, when a particle size distribution is known, the number density in the field can be computed if extinction coefficient is measured.

Although scattered light instruments do require careful understanding, use, and calibration, we do believe that they offer the most viable techniques for problems in fossil demonstration plants. They do not require particle capture as many methods do; they are ideal for in situ measurement; they provide data in a form which is easily handled by fast microprocessors; and they can be made extremely rugged.

Aerodynamic

Particle impactors are currently the standard means of obtaining size distribution measurements under field conditions. Particle laden air is extracted by means of a sampling probe and passed through a series of orifices or slits arranged in order of decreasing size (increasing velocity) and directed against impaction plates. Particles are thus collected on the plates in proportion to their size and information can be gained by counting, weighing or other analytical techniques. Unfortunately, several drawbacks exist which have prompted the need for other methods. Sampling by means of a probe has inherent problems and inaccuracies. Great care must be taken to insure that the sample is extracted isokinetically and that the diameter of the probe and extraction velocities are chosen correctly (to avoid particle deposition). Analyzing the impactor stages after a sample has been taken is also very time consuming. Impactors must be disassembled and careful weighing of samples must occur under laboratory conditions. Weight gain of or loss from the collection substrates is caused by the presence of some gasses and can be a serious problem in data analysis.

Centrifugal devices such as cyclones are also used routinely for particle size determination. Cyclones operate by injecting a particle laden stream tangentially into a tapered conical enclosure. Centrifugal acceleration afforded by the spiral motion determines whether the particle is collected by the cyclone or remains suspended and continues out the exhaust.

Cyclones can be cascaded like impactors to provide a range of particle cut points. Their advantages are that they adapt easily to sampling apparatus and they provide a large collection capacity. Unfortunately, they have the same disadvantages common to impactors.

Centrifugal elutriation devices are also available and this method is the accepted ASME means for flyash classification. Disadvantages of this device, like impactors and cyclones, are the lack of in situ measuring and the time required for sizing analysis. Other disadvantages are that the sample must be collected and then redispersed into the instrument, classification is highly dependent on flow conditions and inlet geometry, and these devices are generally more expensive than impactors and cyclones.

Gravitational devices depend on particle weight to determine a settling velocity and trajectory causing a distribution by size on the bottom of a settling chamber. This method requires the minimization of convective thermal currents and very long periods of time (several hours) to resolve fine particles which makes it an unattractive means to size particles.

Filtration

Particles drawn into a sampling probe can be collected by barrier filtration. The barrier filter can be designed to collect essentially 100 percent of the particles present in the stream. This technique is often used as the final collection stage of an inertial impactor train or series of cyclones. This method can also be used as the only collection device. While it is not an in situ method, it does have the advantage that essentially all the particulates are collected in one place. As with several of the other techniques, it has the disadvantage that size distribution is done by time consuming laboratory techniques such as Coulter counter analysis, optical or SEM microscopy. Accuracy is dependent upon the ability to redisperse the particles. As a rule, this is increasingly difficult as particle size is reduced.

The size distribution of particles in bulk form can be obtained down to about 2 μm by sieving. Sieves for fine particle analysis are pans with

bottoms of electroformed grids. Particles are separated into size fractions by means of a series of sieves and the particle mass retained on each sieve is usually determined by weighing.

Electrostatic

When airborne particles are very small, less than 0.1 μm in diameter, they seldom carry more than one unit of electrostatic charge if in equilibrium with the ambient atmosphere. The mobility of these particles, or rate of movement in an imposed electric field, then affords a measure of their size. An electrostatic device may incorporate either parallel-plate or concentric cylinder electrodes where one is grounded through a sensitive electrometer, and the other is raised to a potential, usually in the 10 to 1000 volt range. The aerosol is passed laminarly through the space between the electrodes and the charged particles migrate to the grounded side and surrender their charge. By varying the applied voltage and measuring the resultant current, a size distribution can be deduced. Unlike the previous mechanical devices, this method appears to fulfill the requirement of in situ operation. The main drawback is the small particle sizes that are measurable. The operable range of electrostatic device is approximately 0.005 to 0.6 μm making this method unsuitable for the larger size range.

Condensation

When aerosol particles are so small that they can only be distinguished with an electron microscope, their presence can be made visible by reducing the pressure in a confining vessel so that moisture is condensed on the particles. An early detecting instrument for such nuclei utilized a vessel with a glass bottom into which an aerosol was drawn and then subjected to expansion. The resulting droplets were counted after the aerosol settled.

Modern instruments operate on the same basic principle, and they still give only number information. The prototype of present condensation nuclei counters formed a water fog by first compressing the air and then adiabatically expanding it. The amount of fog formed is measured by light transmission, and the system is calibrated by allowing the droplets to fall on a microscope graticule and counting them. Later models use photomicrography for calibration. Again, both the fact that a sample must be extracted and much time is needed for data reduction make this technique unsuitable for real time in situ operation.

Diffusion

Diffusion is a classification method for very small particles, as small as 0.001 μm. An aerosol is sent through a tube and Brownian motion of the particles causes impingement and adherence to the tube wall. The deposition rate is a function of particle size in that the concentration of small particles decreases more rapidly than that of large particles. Disadvantages include the fact that the aerosol stream and tube must be in thermal equilibrium, particles larger than approximately 1.0 μm should be removed upstream of the tube, and gravity and turbulence may confuse the deposit. In general, these devices have sizing capabilities in a range much below that required here.

Acoustic

A relatively large airborne particle, e.g., 15 μm, passing rapidly through a gradually tapering tube that expands rapidly after a small throat, produces an audible click that can be counted or recorded electronically. The click originates near the end of the throat as a shock wave due to boundary-layer disturbance in the throat created by the particle. The device is simple, but no embodiment yet designed responds to small particles, and the response that is given is only a rough indication of particle size.

Particle size can be deduced from the sinusoidal paths particles follow if a slowly rising aerosol stream is dark-field illuminated and exposed to low-power sound waves. The method is obviously tedious and is to be recommended only if special circumstances dictate its use.

A measure of the particle size and concentration of aerosol can also be deduced from the extinction of ultrasonic sound waves passing through an aerosol and through the same gas without particles. Conditions are most favorable for the application of sound-attenuation techniques with aerosols of high concentrations. This makes such techniques of dubious practical value in most instances.

Vibrating Crystals

Piezoelectric crystal mass monitors in combination with an impactor train would appear to hold some promise for an in situ particle size distribution and concentration device. The piezoelectric mass monitors are intriguing because of their extreme sensitivity. However, such a device can be expected to be subject to several sources of error: linearity problems could require short sampling periods especially in high concentrations, errors could

result from temperature or humidity fluctuations, non-uniform particle density could be interpreted as changes in concentration and the devices would require a crystal cleaning device for subsequent readings.

Filter Tape With Beta Absorption Mass Monitor

A device of this type has been used to measure the mass of atmospheric fine particle aerosol. Since it is basically a mass measurement device, it is probably not easily adapted to in situ measurements. Particle sizing would depend upon impactors and the mechanism required for moving the filter tape would be prone to problems in the severe environment contemplated for the in situ fine particle analyzer.

Contact Electrification Devices

This is a class of instruments which provides an electrical current proportional to the particle mass concentration in a gas stream. They work by transfer of charge from the particulate to the instrument probe through particulate probe collisions. The sensitivity of the devices depend on the electrical resistivity of the particulate as well as upon the condition of the surface of the probe. The theory for operation of these devices is poorly understood. They can be expected to suffer from the effects of sticky particles and from particulate streams of varying composition. Furthermore, the device does not seem well suited to measurement of particle size distribution.

3. FURTHER DISCUSSION OF OPTICAL TECHNIQUES

3.1 Imaging Methods

There are a number of considerations and definitions that apply to all imaging techniques. The most basic of these is resolution. For a perfect imaging system, a point source of light will be imaged to a finite-sized image (impulse response, point spread function, blur circle) because of the laws of diffraction. This image size represents the smallest object which can be resolved in the image. Smaller objects can be detected in the image if the signal-to-noise ratio is sufficient, but the dimension of smaller particle images can be no smaller than the resolution limit. The diffraction limited resolution is given approximately by

$$R_D = 1.2\ S\ \lambda/D \quad . \tag{1}$$

Where S is the lens to object distance, D is the diameter of the collecting system (lens or limiting aperture) and λ is the wavelength of the light.

Except for very limited cases, resolution is worse than this because geometrical aberration terms must be added.

A second and just as important consideration is optical system noise or signal-to-noise ratio. Every optical system scatters useless light into the vicinity of the image being analyzed to the extent that this usually limits the utility of an imaging technique. In particle field diagnostics, the situation is amplified by the fact that all particles besides the one being looked at at a given time must be considered potential sources of optical noise. This means that not only the optical system but the particle field itself must be considered in evaluating ultimate system capability. Although ambient light usually represents a noise source, methods are now available to effectively eliminate this as a problem.

Photography and Electro-Video Recording

Photography is widely used to record particle images. To each object at a distance S, a corresponding image plane S' exists. Over some finite variation about S, called field depth, an image in the plane S' remains essentially in focus. Depth of field is given approximately by

$$S = \frac{R^2}{\lambda} \quad . \tag{2}$$

Therefore, higher resolution studies require a thin sample volume. If the particle number density is low or the resolution requirement high, this creates difficulty in that the number of focused images can be insufficient, requiring many photographs.

Holography

Holography relaxes the depth of field problem suffered by photography. Typically, for a given resolution holography expands the image storage capability by three or four orders of magnitude. Still, the process involves a processing time for the recording which rules out real time diagnostics. Furthermore, data reduction methods currently are quite tedious and not acceptable for this problem. Holography technology is almost certain to produce real time recording and reduction materials which when combined with rapid electronic image analysis would qualify this as a valid method. But these appear several years away and cannot be considered for immediate use.

Shadow Spectrometry

One of the most limiting problems in imaging instruments is the extraction of data from large numbers of images. When one must move from image to

image making selected measurements, the data collection time makes it difficult to consider statistically large samples. Shadow spectrometers collect data from the image of a particle electro-optically as it passes through the sample volume, using the motion of the particle to sweep it over tiny sensing elements which are arranged in a linear array. The size of the particle is then directly related to the number of elements shadowed by the particle during its transit.

Numerous such devices have been built to measure such things as wire diameter to spark gap clearance. The most widely-developed instruments for particle sizing using this principle are those of Particle Measuring Systems, Inc., Boulder, Colorado. A linear diode array, comprising from 17 to 24 diodes having individual diodes of about 80 micrometers diameter separated by 200 micrometers, comprise the sensor. The size measurement range depends upon image magnification. The lower size limit as well as resolution is the diameter of the individual sensing element divided by magnification. The maximum size range, therefore, in the magnified image is from one diode diameter to the full array length.

The instruments have logic to reject images crossing the end diodes to prevent fractions of images from being included. This does require some statistics for larger particles because the sample volume diameter is smaller.

A chief point of difficulty in using the principle in the small size range is caused by diffraction problems. The device is based upon geometrical optics. Only those particles in perfect focus on the linear array can be sized properly in the strictest sense. Particles which are not in focus present their diffraction patterns to the array. The PMS, Inc. instrument incorporates a type of focusing logic which considers that a diode has been shadowed only if the intensity on it has been reduced by at least 50 percent (or some other pre-set value). This also defines the particle edge.

The interpretation of data from this device becomes rather complex in the range where geometrical optics is not applicable (actually starting at about 100 micrometers and below). The sample volume becomes a function of particle size and the particle size readout becomes a function of particle position in the sample volume. Nevertheless, when calibrated and used properly, the PMS device has proven to be a powerful instrument in particle diagnostics. Unfortunately, many users of this instrument are using it improperly and are generating data which is incorrect.

These instruments can measure in situ particle fields and are non-perturbing to the extent that the particle field flows between two probes which are separated by distances ranging from a few centimeters up to about thirty centimeters.

The power of these instruments lies in their ability to take, classify and store information describing large numbers of particles in a short time. Also, information initially emerges in binary form which is ideal for electronic processing.

3.2 Scattering Instruments

When a particle is illuminated, it scatters light by an amount and in a spatial distribution which depends on many factors. Special conditions reduce the number of variables or provide for the factoring out of such variables. Commercially available instruments rely either upon these principles or upon calibration.

Low Angle, Forward Scattering with $D > \lambda$

When the particle diameter is greater than the light wavelength and when forward scattering is considered, the Fresnel-Kirkhoff approximations to diffraction are applicable. The intensity of forward scattered light is given for a circular disk.

$$I(\omega) = I_0 k^2 a^4 \left[\frac{J_1(ka\omega)}{ka\omega}\right]^2 \tag{3}$$

where

I_0 = the incident flux per unit area

$k = 2\pi/\lambda$

ω = sin θ where θ is the angle relative to the incident beam

a = particle radius.

Consider an instrument that collects the scattered light making a single measurement per particle. The collected light is an integral of intensity over the collecting angle. When the collecting angle is small enough such that $J_1(ka\omega)/ka\omega$ is constant, this is approximately

$$I_t^0 \approx \frac{\pi}{4} I_0 k^2 \omega_0^2 a^4 \quad . \tag{4}$$

The above result provides direction for a particle sizing instrument collecting a small amount of forward scattered light providing a signal proportional

to a^4. Notice that since the scattering is based upon diffraction theory, the scattered light is not dependent on refractive index.

Examples of such instruments are produced by Royco Instruments, Inc., Particle Measuring Systems, Inc., Environmental Systems Corp., Climet Instruments, Inc., Spectron Development Laboratories, Inc., and others.

Scattering at Wide Angles

If calibration is to be considered acceptable, then the only reason to use forward scattered light is that there is more of it. In fact, some benefits emerge when large angle scattering is used in sizing. The collected intensity is approximated by

$$I_t^L = \int_0^\infty I(\omega) 2\pi\omega d\omega \approx \pi I_0 a^2 \qquad (5)$$

The result is that when all scattered light is collected, a signal proportional to a^2 results.

Scattering Ratio Measurement

One method which reduces sensitivity of an instrument to refractive index and incident intensity variation is the measurement of intensity ratio of scattered light at two angles.

This type of measurement does not require single particle scattering to provide useful information. When an ensemble of particles is illuminated, it can be shown that measurement of intensity ratio of light scattered at two angles can lead to mean diameter of the sample.

Particle Sizing Interferometry

Particle sizing interferometry operates on a principle illustrated in Figure 1. By focusing and crossing two equal intensity laser beams, a small ellipsoid in space is filled with parallel, equally spaced fringes of light intensity (separated by δ). The ratio of the term designated AC to that designated DC can be used to compute particle size. Furthermore, determination of τ provides velocity of the particle.

This instrument has been used successfully in the diagnostics of particle fields for submicrometer sizes and larger. The fringe spacing is chosen to equal the largest particle under examination.

A particle traversing this sample volume scatters light with an amplitude modulation in time as it traverses the fringes. The smaller the particle, the more closely the scattered light modulation resembles the intensity

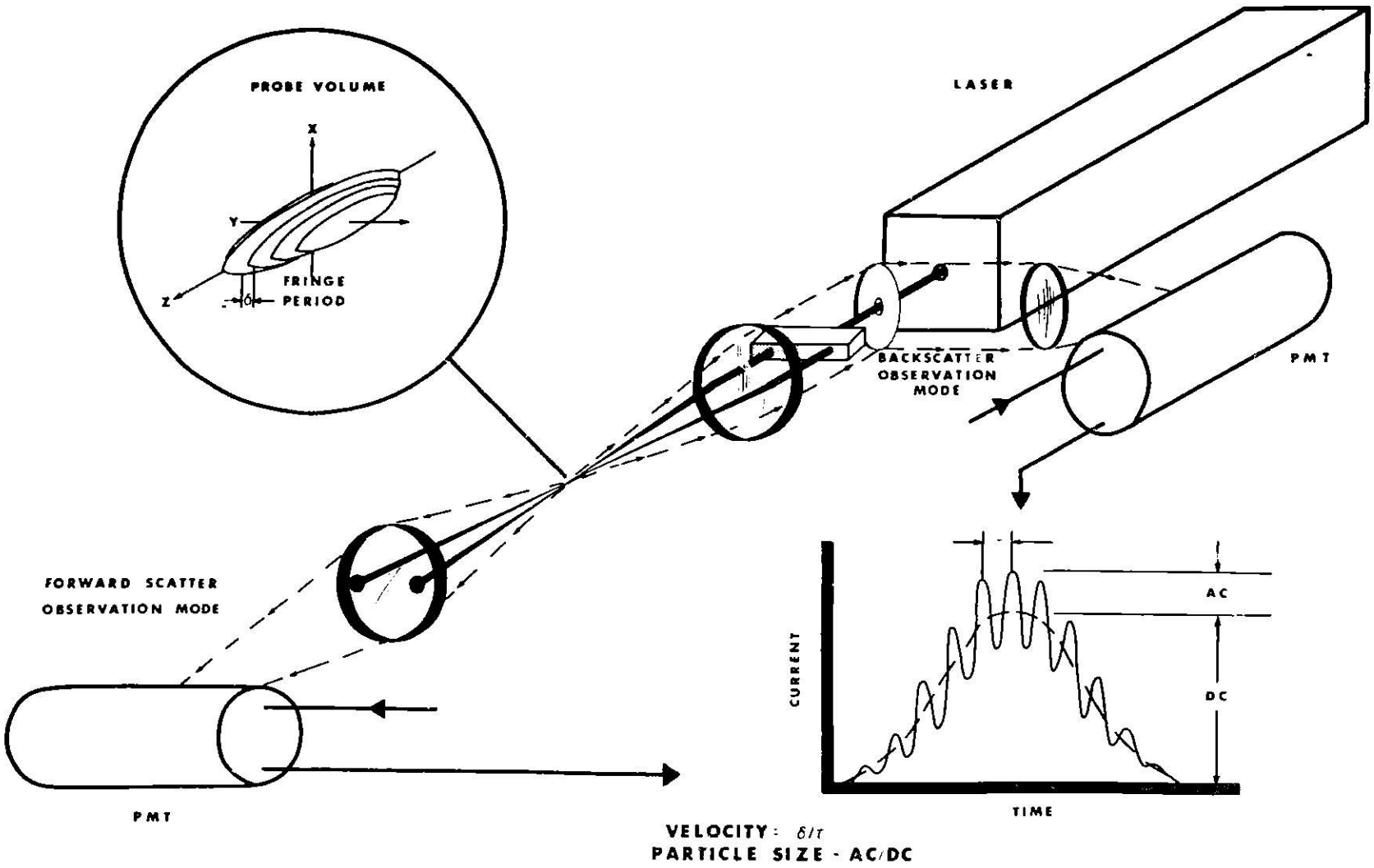


Figure 1. Particle Sizing Interferometer, Principle of Operation

distribution in the sample volume, the scattered light signal being a type of convolution of the particle geometry with the probe volume intensity. As the particle size increases, the scattered light signal increases in strength, but decreases in modulation percentage.

The measured parameter has been termed signal visibility, the ratio of the minimum to maximum amplitudes of the scattered signal.

This technique possesses the desired features of the best scattering methods, a well defined and controlled sample volume, a measurement of ratios of intensity as opposed to absolute magnitude, and perhaps the most important feature, an independence from refractive index of the particle. In principle, the instrument needs no calibration. Furthermore, particle velocity is derivable from the signal.

Unfortunately, like every other particle diagnostic technique, intricacies of scattering phenomena produce discrepancies in the technique at small size ranges. Furthermore, as with other methods, the characterization of non-spherical particles has not been clearly established.

Recent theoretical work shows that the measured parameter (signal visibility) is multiple-valued in the size range below 5 micrometers and, therefore, is insufficient by itself to serve reliably as an accurate size parameter throughout the range. To remedy this problem we have incorporated a second measured parameter to remove the multi-valued nature of the signal. The second parameter in our current system is scatter coefficient. The addition of this measured parameter was not difficult since all of the elements of such a scheme were already present in the system. Our belief is that this scheme has the potential for providing the most reliable, accurate system for diagnostics of particles of any currently available.

Figure 2 illustrates a hybrid system on which Spectron is currently performing laboratory tests. A small helium neon laser serves as the light source. The laser beam is passed through a sampling volume where particles scatter radiation into the receiving system. The transmitted beam is then stopped by a light trap at the receiving system. A photo diode situated in this light trap monitors the basic laser output. Forward scattered light is collected by a lens system which conducts the light to a beamsplitter and then to a photosensor. The collected light provides a measure of the scatter cross section of the particle into this solid angle.

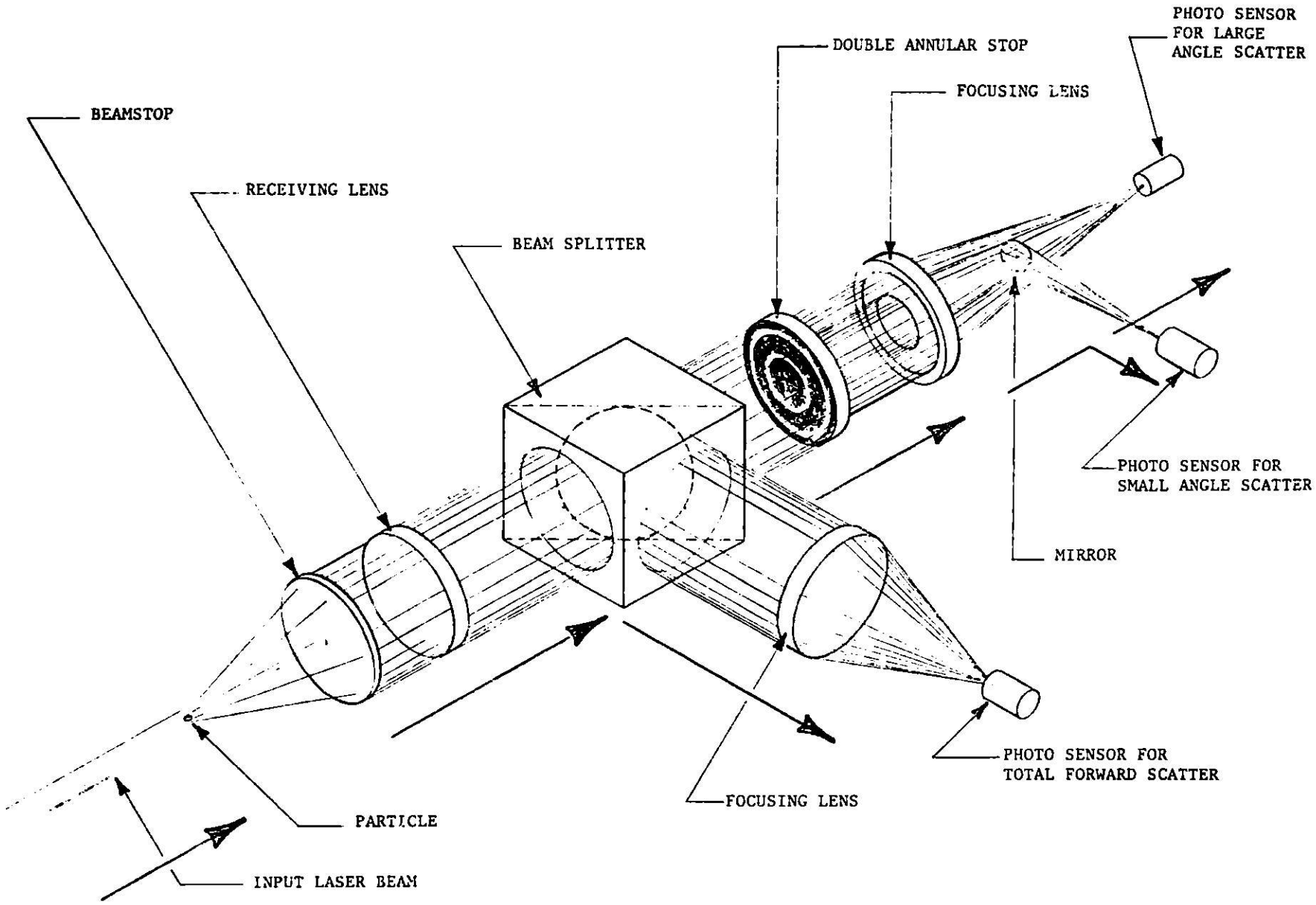


Fig. 2. Light Scattering System Concept

It is critical that the receiving system be properly apertured such that the photosensor "looks" only at a central uniformly illuminated sample volume. This reduces the error caused by particles passing through regions of higher or lower intensity.

The purpose of the beamsplitter is to allow forward scattered light to be analyzed additionally by the intensity ratio method. Light passing beyond the beamsplitter is divided into two conical sections or solid angle increments representing two angles of forward scatter. Light scattered into these two angles is separately detected by two detectors. A third detector is used to balance the first two detectors such that a given incident light level will produce the same reading on either detector. A simple system check procedure insures that this condition is always met.

When a single spherical particle passes through the sample volume, either method should provide an acceptable measure of particle size. When the particle is not spherical or when more than one particle lies in the sample volume, the two readings will not agree. A second check which can easily be incorporated in the system is an annularly adjustable stop which varies the position on the solid angle from which ratios are measured (see Figure 2). It is not clear at this time if this additional check is needed.

This instrument can be used in a variety of modes, some of which are described here. The most basic mode is to provide logic which accepts only those signals which agree on particle size to within a preset error. A record of percentage of rejected signals would be available. This method of providing double measurement for signal validation is a commonly accepted procedure for improving data quality in many types of optical instrumentation. In fact, it does not greatly increase the complexity or cost of the instrument since only the probing head (the simplest, least expensive element) is involved. The validation logic is rather simple, having been developed already for our laser Doppler instruments.

When particles are not spherical, the two measurements can in principle produce an asphericity parameter which may be useful in the diagnostics of such fields. The significance and utility of the two measurements for characterizing aspherical particles has not been evaluated at this time.

As described so far, the instrument functions in an individual particle sensing mode. While this is the only valid way to insure an accurate particle size distribution (without questionable assumptions), measurements on particle

ensembles can provide useful diagnostic information such as total cross section and mean particle diameter.

3.3 An Application in a Fluidized Bed Combustor

Under ERDA Contract No. EX-76-C-01-2413, SDL demonstrated one particular kind of laser system for particle measurements at the ANL FBC facility. The unit employed was the previously described laser interferometer system that simultaneously measures particle size and velocity. The instrument monitors continuously in time particles passing through a small spatial probe volume (Figure 1).

For a given fringe period δ, the laser interferometer system can size particles over about a decade of size range. Broader size ranges can be measured by several approaches, such as dual or multiplexed systems. The size of the probe volume is controlled optically and electronically so that usually only one particle is in the probe volume at a time. Reference 1 presents a detailed formulation and description of the principles employed in the laser interferometer instrument.

The system used at the ANL FBC installation was an existing SDL prototype laser interferometer. The instrument was designed for general utility and demonstration. It has been used in a wide range of measurement platforms, including helicopters, environmental simulation chambers, and icing test facilities. Since it was not designed specifically for FBC measurements, it is not as compact or efficient as possible for this application. However, it served adequately to demonstrate the potential utility of laser techniques for coal processing facilities.

Figure 3 shows the optical and electronic components that were used at the ANL FBC. The optical system, shown in the bottom picture of Figure 3, has four selectable channels or fringe periods that are used for measuring particles in different size ranges. The four channels cover the size range from about 0.2 microns to 500 microns. The electronic processor, called PMAC Model 554, is also shown in Figure 3. This unit calculates size and velocity for each particle scattered light signal as discussed above. In addition, the unit has a built-in histogram generator which permits the generation of size or velocity distributions. Normally, the histogram generator breaks the size or velocity range into 15 discreet bins. In developing the histogram, particle data is collected until a prescribed criteria is met. Primary criteria used are total number of counts (e.g., the number 1000 or 10,000 counts), or

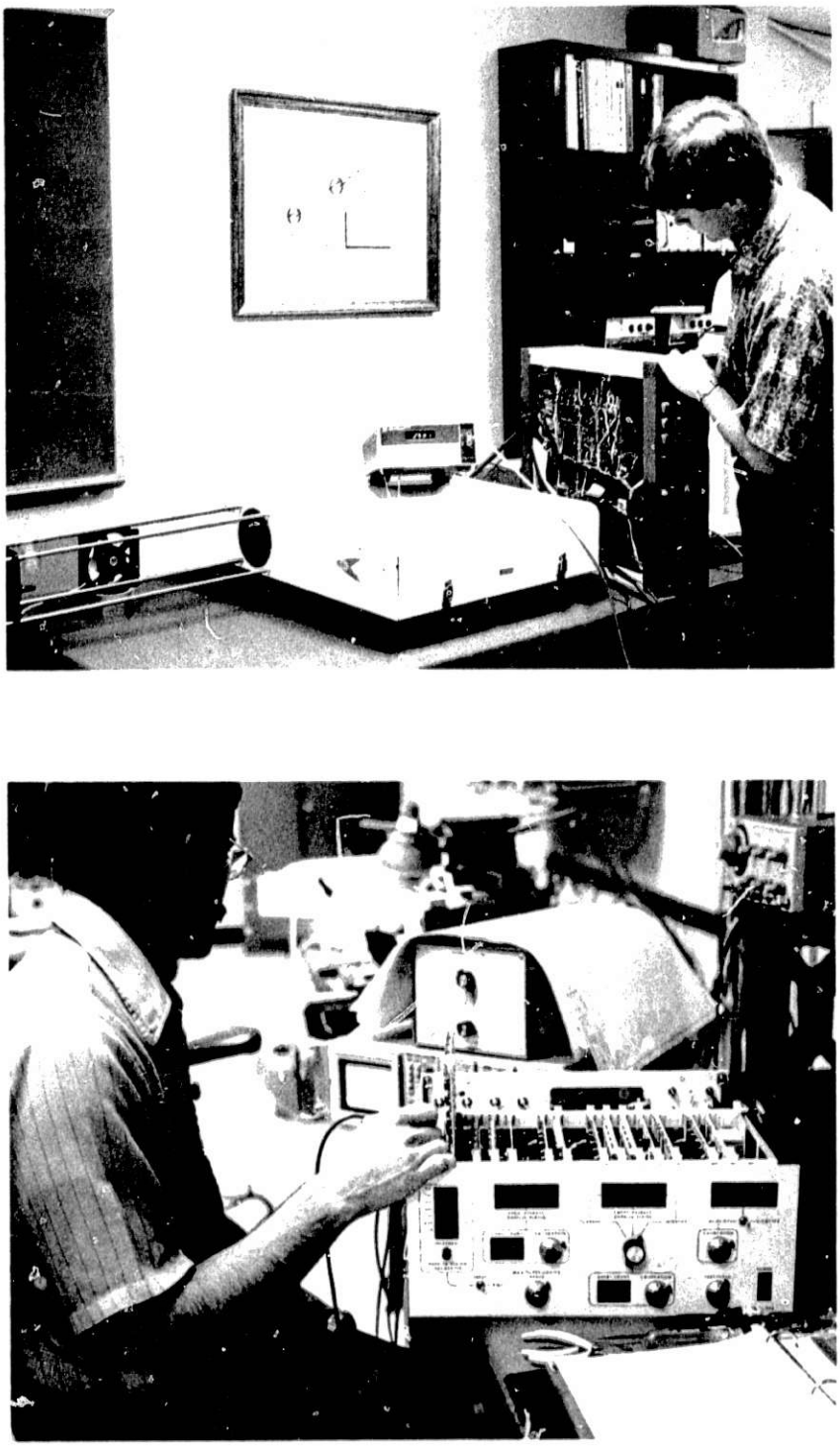


Figure 3. Laser Interferometer Components

particles are counted for a given period of time. These conditions are dialed in on the front control panel of the electronic processor. At the ANL installation, the histogram data was printed out on a paper tape printer shown in the bottom picture of Figure 3. However, the histogram data can easily be fed to other systems, such as a minicomputer or control system.

Figure 4 shows the optical system installed at the ANL FBC facility at one of three stations where measurements were made. The picture on the right in Figure 4 shows a closeup with the cover of the optical system off, and next to the optical windows that gave access to the flue gas. The system was used in the forward scatter mode only in this application.

Very little data analysis was performed by SDL on this program. The ANL collected most of the data, and performed most of the data analysis. An ANL report documenting the results of their data analysis will be available in the near future. Figure 5, however, illustrates typical size distribution data obtained with the unit at this installation. Coulter counter data from the same station is included in Figure 5. The data are in qualitative agreement. A detailed discussion about possible causes for data variance between laser interferometer and other measurements (Coulter counter, cascade impactors) is presented in SDL's final report on this work (Reference 2). Figure 6 shows typical histogram data for one of the observation locations.

4. CONCLUSIONS

Recent applications of optical instrumentation systems demonstrate their utility for critical measurements in coal processing systems. They have been successfully employed in a wide range of harsh conditions, including high temperature and pressure flows and severe mechanical environments. Both particle field and gas flow properties have been measured in these applications.

Optical instruments offer a unique combination of advantages for coal facility measurements. These include high accuracy, in situ real time data acquisition with instrument hardware remote from the flow being monitored. Consequently, they are ideal candidates for use in executing critical control functions.

Carefully selected optical techniques and optimally designed configurations can be employed for coal processing measurements. Candidate systems vary in level of complexity and data detail provided and can be matched up with specific measurement requirements in demonstration plant operation. For

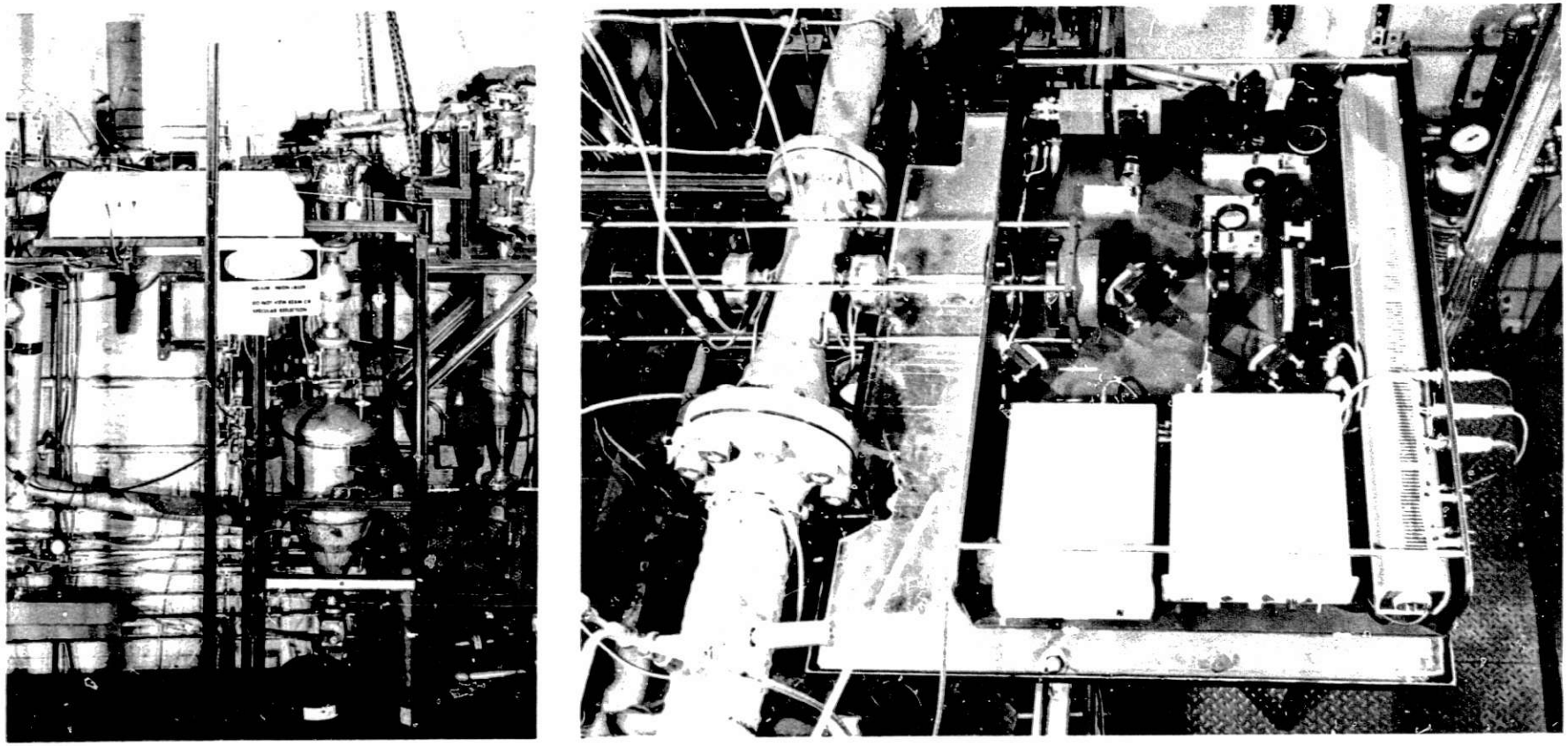


Figure 4. ANL Installation at ANL FBC Facility.

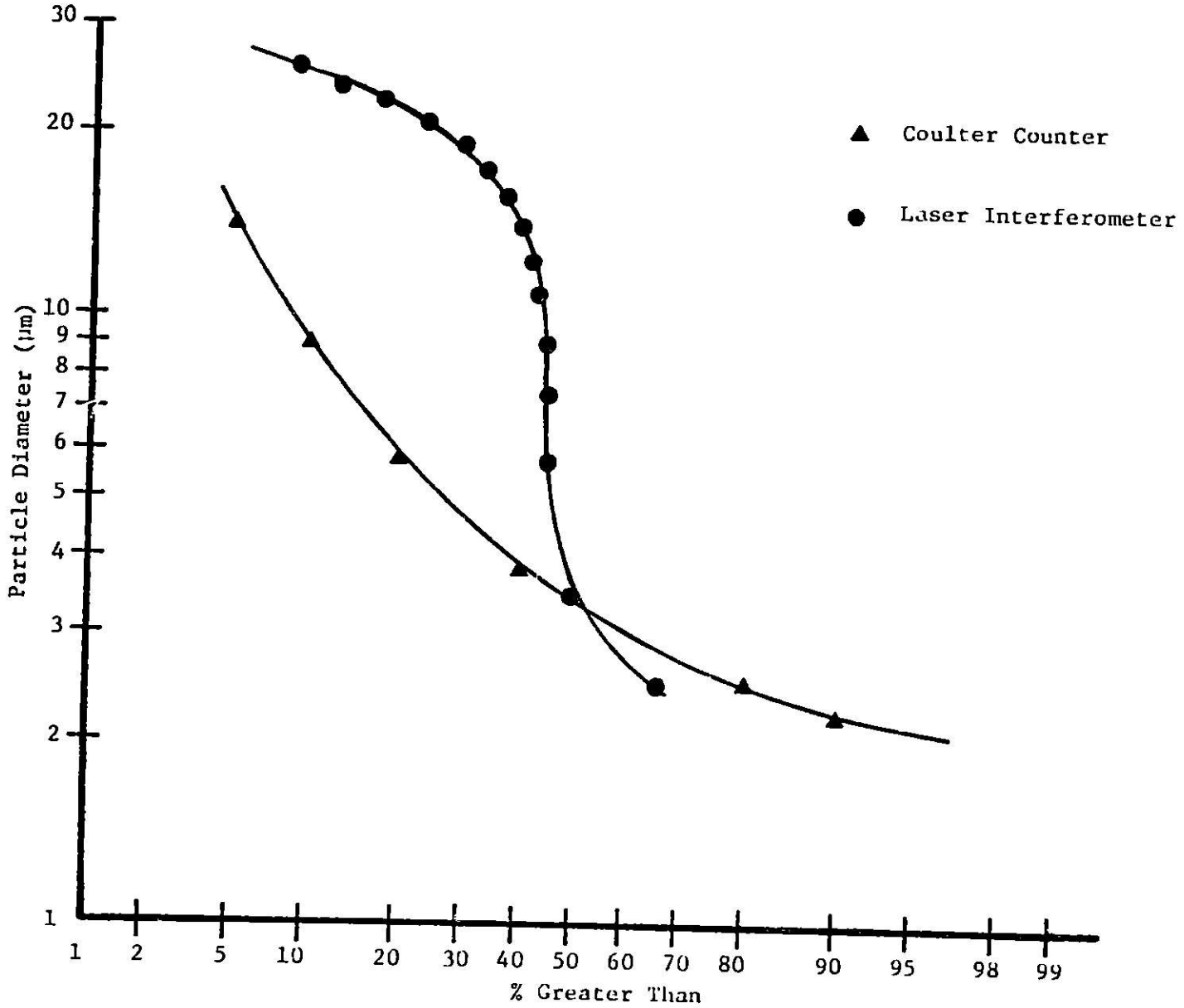


Figure 5. Typical Size Distribution Data from Second Observation Position.

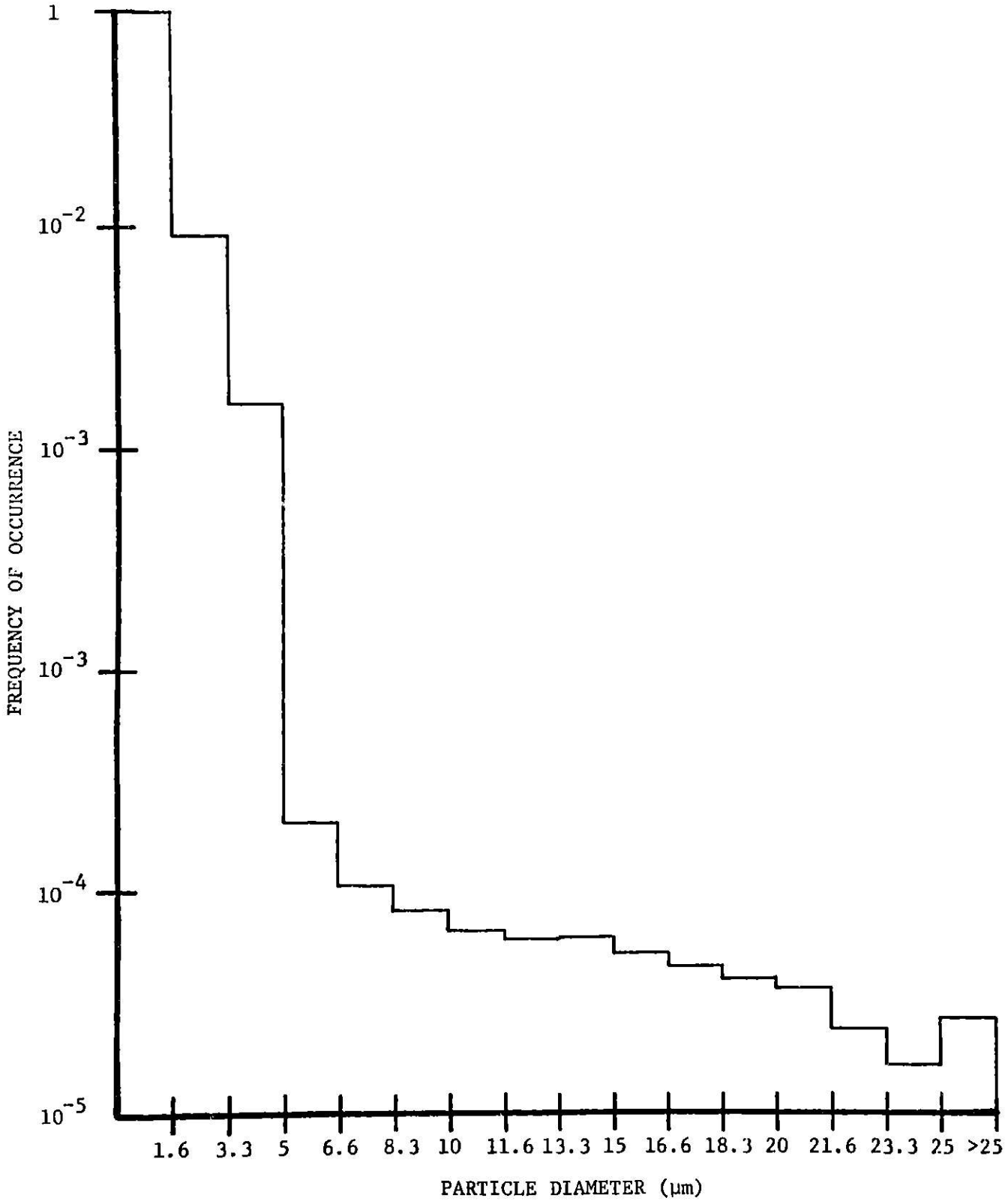


Figure 6. Typical Histogram Data from Second Observation Position.

example, go-no-go data on particle environments requires a less sophisticated system than is needed for detailed size distribution measurements. A development and demonstration program will yield optical instrumentation systems needed to fill a vital role in coal processing demonstration plant operation.

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2. Spectron Development Laboratories, Inc., "Laser Interferometer Analysis of Flue Gas Particles from a Fluidized Bed Combustor," SDL No. 77-6171, Contract No. EX-76-C-01-2413, 1 April 1977.

QUESTIONS AND ANSWERS

J. D. Trolinger

Spectron Development Laboratories

J. A. Consiglio, Solva-Tek Associates

Q. Most optical instruments sample a small volume. Usually, large flow ducts are characterized by spatial distributions of particulates. Have you done any work toward getting integrated values for the entire duct?

A. The types of instruments you ask about must measure more than one particle in a sample volume at a time. The most accurate measurements are those cases where you can examine one particle at a time. Our approach at this time is to scan the single particle instrument to take samples. Typically, the instrument collects a statistical sample in a very short period time. We are now developing an instrument which can be optically scanned, so our approach is to zoom the sample volume from one size of the duct to the other, taking statistical samples at a number of points across the duct.

A. P. Klotz, Foster Wheeler Energy Corporation

Q. What success, if any, have you had with coal oil slurries? Are you working to develop instruments for this area?

A. Our current development is actually to take our laboratory type intruments and specialize these for operational and control measurements. We need to miniaturize the components and we need to make them more portable. We're actually proceeding in a direction of producing instruments that would be operable by not necessarily technical people for controlled functions.

J. P. Meyer Oak Ridge National Laboratory

Q. Is it possible to quantify the effects of turbulence on distributional measurements, since density gradients cause a loss of coherent resolution in the optical beam?

A. We have done a considerable amount of work on turbulence cases. In fact, the velocity measuring segment of the instrument is used to study turbulence. What we find is that when the measurements can be made in extremely short times and in small sample volumes, statistical numbers of measurements reduce the effect of turbulence. Turbulence does, as you say, distort the coherence of the light in the sample volume. When this happens, the measurement may not be good. Turbulent cells move through the sampling region in a random fashion and sometimes there are periods of time when we do get no measurements. There are times when the instrument does function properly. Electronic logic rejects that type

of information which is distorted by turbulence. Turbulence reduces the operational time of the instrument by some percentage.

Q. Although it is not possible to rigorously apply spherical analysis to non-spherical geometries, is it still possible to extract meaningful results, since statistical considerations can average out any uncertainties?

A. I believe this is true. We believe it possible to average out properties statistically. But we don't know exactly what the statistic is yet. We have to take samples that are like the materials of interest and use some of the other particle diagnostic methods I mentioned to determine what the statistic is. We can calculate the correct relationships if we know that the particle is cylindrical or cloisterous.

W. O'Donnel, Monsanto Company

Q. Does the holographic technique depend on a photographic film which needs to be developed?

A. At the present time it does. That is the basic reason why it is not applicable as a primary instrument for control. There are new materials; the most promising is thermo-plastic material, recently offered by a company in Germany called Rottenkolber. This is not a photographic film. The recording is made and immediately developed and data is accessible within seconds after. Such materials have become available in useable forms just in the past year. I consider that these hold promise for some future date. The method is still very expensive, and I feel that we are several years away from replacing photographic films.

J. Steiner, Acurex

Q. Have you compared your instrument readout to conventional measurements (e.g., impactors, cyclones) at Argonne?

A. There was a comparison made at Argonne with capture sample measurements (an impactor and a Coulter counter). The best thing I can say at this time is that the results were not drastically different. We have explanations for the differences in the two. As mentioned previously, the two really measure different things. The Coulter counter measures an electrical diameter, while optical instruments measure optical cross sections. The range of sizes compared well. The distributions did not compare so well. The data is still being analyzed by the people at Argonne National Laboratory.

E. E. Geraci, Leeds and NOrthrup Company

Q. What is the minimum particle size that can be resolved with your instrument?

A. We have used the instrument down to 2 microns. We have not really calibrated the instrument to sizes below about 5 microns. The calibration of an instrument like this for large samples below five microns is difficult. We took readings like everyone else does below five microns,

down to about 2/10ths of a micron. But there are indications that our instrument measures a multiple valued function below about 5 microns, and it appears to make that measurement accurate, we must combine the measure of signal visibility with scatter cross sections. So I can say that although we have used the instrument down to sub-micron measurements, its usual application stops at 4 to 5 microns.

ON-LINE PARTICULATE ANALYSIS FOR ADVANCED COMBUSTION SYSTEMS

E. S. Van Valkenburg
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ON-LINE PARTICULATE ANALYSIS FOR ADVANCED COMBUSTION SYSTEMS

by E. S. Van Valkenburg
Leeds & Northrup Company

INTRODUCTION

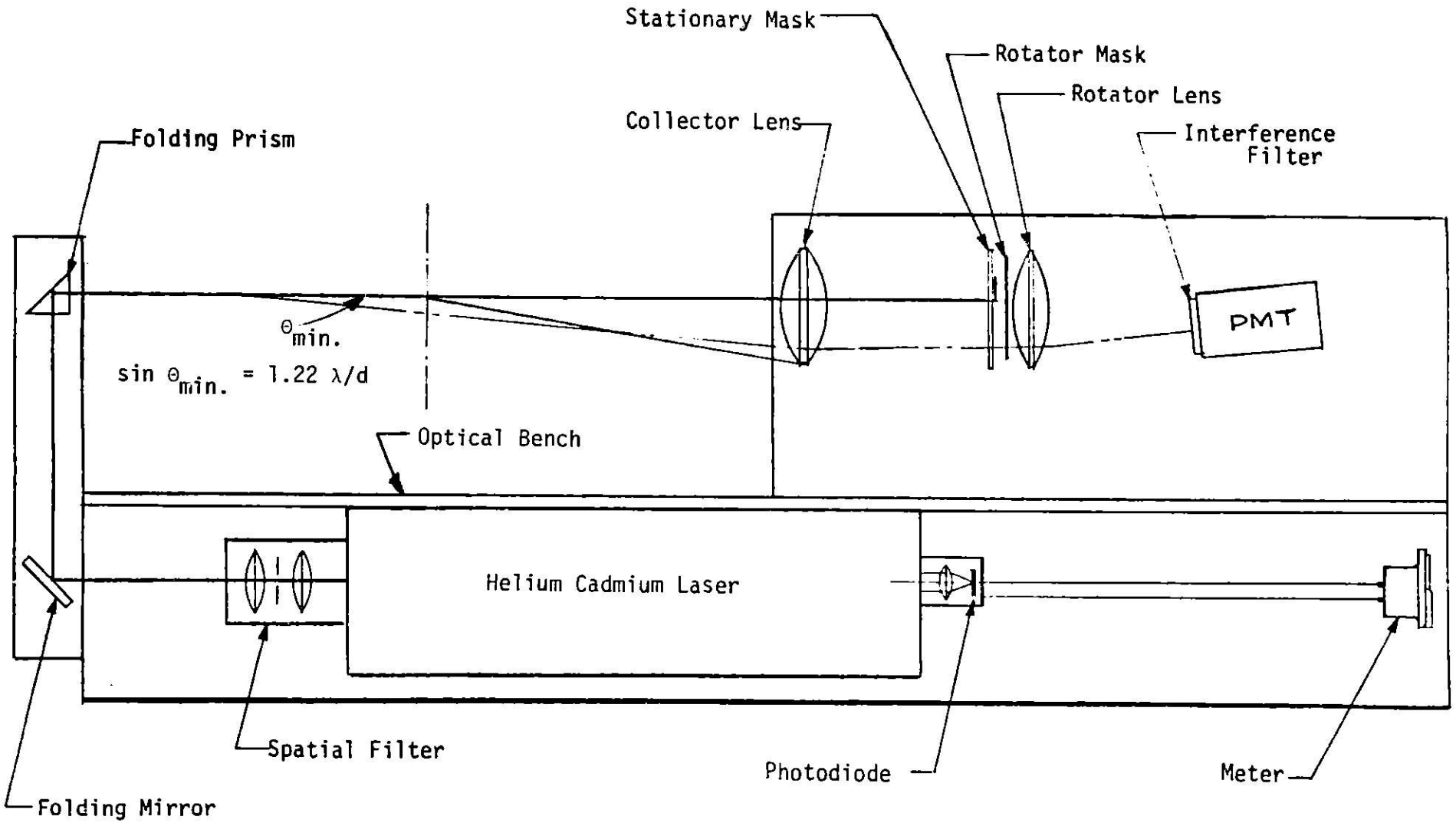
An on-line particulate analysis instrument is being developed by Leeds & Northrup Company under ERDA sponsorship for measuring the loading and size distributions of particles entrained in the product gas streams of advanced combustion systems. A prototype instrument has been designed and constructed. This instrument has now been delivered to the Argonne National Laboratory (ANL) where it is being evaluated on a fluidized-bed combustion system. Following these tests at ANL it will be delivered to the Curtiss Wright Corporation where it will be installed on the Small Gas Turbine Fluidized-Bed Combustion System.

This type of instrumentation will enable near real-time monitoring and analysis of gas entrained particles by optical means. It will be used to evaluate performance of fine particle separators and to measure size distribution and concentration of particles at the inlet to gas turbines in direct combustion coal-fired systems. The latter application requires that the instrument be adaptable to medium size gas ducts which transport high temperature (1500° - 2000°F) high pressure (up to 10 atm.) gas from the final stage of filtration to the turbine.

The instrument developed by Leeds & Northrup is based on the company's prior research in low-angle forward scattering of light by suspended particles. I will first describe the particulate instrument designed for advanced combustion systems applications. Then present the basic concepts of this type of instrumentation and conclude with a discussion on our laboratory test results and a summary of its potential performance capabilities.

INSTRUMENT DESCRIPTION

A schematic diagram of the optical train of the ERDA instrument is shown in Figure 1. This instrument consists of optical elements mounted to an optical bench which extends under a horizontal run of the combustion system duct. (The duct is not shown in the schematic, only its vertical center line.) The illumination source is a helium cadmium laser mounted to



Particulate Instrument Schematic
Figure 1

the underside of the optical bench. Folding optics, attached to the left end of the optical bench, direct the laser beam across the duct where particles in the gas stream, which are illuminated by the beam, scatter the light. The scattered flux is collected by a lens and focused on a set of function masks. The portions of flux, which are transmitted through the function masks, are focused by a second lens on to the photomultiplier detector.

The output power of the laser is measured by a silicon photodiode which detects radiation from the rear Brewster window of the laser. This signal is displayed on a meter for ease of adjusting the laser alignment to maintain peak power output.

A photograph of the prototype instrument is shown in Figure 2. This instrument consists of the optical subsystem assembly, an electronics package, laser power supply, and a digital line printer. All units, except the printer, are contained in NEMA 12 class enclosures to meet industrial environmental requirements. The laser and receiving optics units contain thermostat controlled heaters so that the optical subsystem may be installed on a gas duct which is located outside of a building.

The electronics package includes a microcomputer, visual display and all the operating controls. This unit can be located up to 200 feet from the optical subsystem. The digital data printer is used to log the output measurements and can be located remotely from the electronics package, if desired.

A plastic mockup of a 4 inch I.D. duct is shown in the optical sampling zone of the instrument in Figure 3. The opening from the folding optics on the left to the collection lens bezel is 30 inches. The vertical clearance above the optical bench to the laser beam center line is 9-1/2 inches. These dimensions were chosen to accommodate a 10 inch I.D. duct with tee section viewing ports extending on two sides of the duct. The tee sections contain quartz windows and means for air purging to keep the windows clean of deposits.

Mechanical adjustments are provided on the folding optics for alignment of the optical train to the duct windows after the instrument is installed. The instrument can be mechanically mounted to the duct through

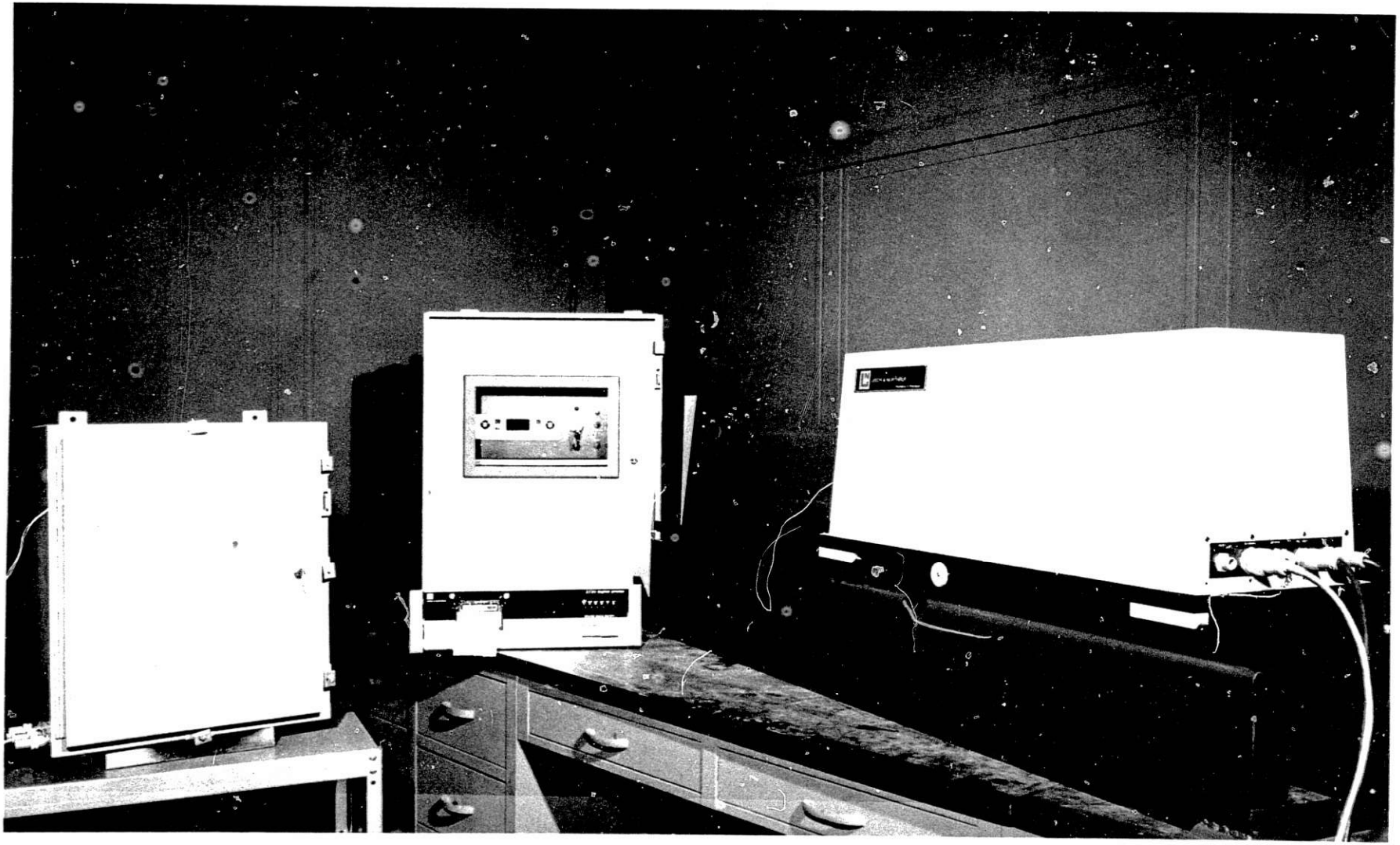


Fig. 2. Prototype Particulate Instrument

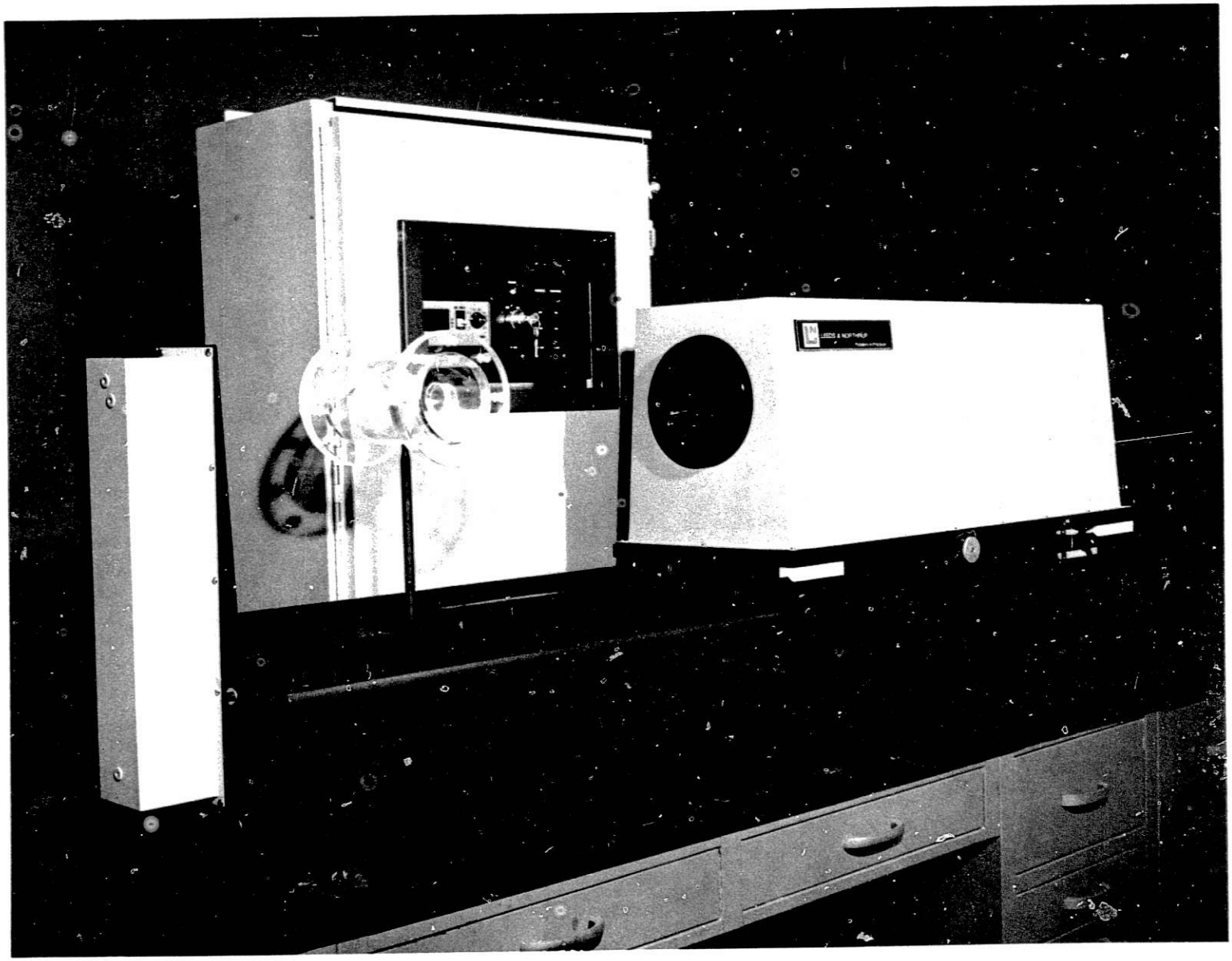


Fig. 3. Optical and Electronic Subsystems with 4" Duct Model

the load carrying base structure.

Since many of you may not be familiar with the basic measurement principles, I will review the theory briefly and discuss the significance of the measurements.

OPTICAL SCATTERING MEASUREMENTS

When small particles are illuminated by light, portions of that light are scattered at various angles depending on the wavelength of the light, size and shape of the particles and index of refraction. The distribution of scattered light observed at great distance from a small object is referred to as the Fraunhofer diffraction pattern, and from this pattern, the cross-sectional area of the object can be determined. If the objects are spheres and the illumination is monochromatic, the angular extent of the diffraction pattern is given by the equation: $\sin \theta = 1.22 \lambda/d$, where θ = half angle to the first minimum of the pattern, λ = wavelength of the light source and d = particle diameter. Thus, large particles produce a narrowly defined flux pattern, while smaller particles diffract flux over wider angles but with lower flux intensity. The total intensity (I_i) of the scattered flux is given by: $I_i = Knd_i^2$, where K is a calibration constant and n is the number of particles of diameter d_i.

If a specially designed transmission filter is placed in the Fraunhofer plane of the collection lens, the intensity of the transmitted scattered flux can be made proportional to various powers of the particle diameter (d^n). In particular, a set of masks has been designed to yield signals proportional to the second, third and fourth powers of the particle diameters.

The transmission characteristics of these mask functions are optimized to yield a uniform response over the total range of particle sizes to be measured. These masks are assembled on a rotating disk such that the three functions are separated in angular extent and allow serial extraction of each of the desired signals. Computations of the particle size distributions and total volume of the particles are implemented as follows.

For a collection of particles, the optical signal from each portion of the mask can be expressed as a summation of particle radii raised to the appropriate power for each mask segment. This summation can be written in

an integral form when the particle distribution is expressed as $D_N(a)$, the number density distribution by particle radius, so that $D_N(a)da$ is the fraction of particles with radii between a and a + da. For example, the flux, S_3, passing through the 3rd power mask is

$$S_3 = K_3 E \int_0^\infty a^3 D_N(a)da, \tag{1}$$

with K_3 an instrumental constant, and E the intensity of the probe beam. S_3 is thus proportional to the volume of particulate matter in the beam.

Similarly, the flux passing through the second power and fourth power masks may be written, respectively, as

$$S_2 = K_2 E \int_0^\infty a^2 D_N(a)da, \tag{2}$$

$$S_4 = K_4 E \int_0^\infty a^4 D_N(a)da, \tag{3}$$

where K_2 and K_4 are instrumental constants.

Frequently, for practical purposes, it is convenient to describe particulate size distributions in ways other than the number density. Three different ways of expressing the same particle distribution are shown in Fig. 4. One example [Fig. 4(C)] is the volume distribution $D_V(a)$. This is defined such that $D_V(a)da$ is the fraction of the total volume contributed by particles with radii between a and a + da.[1]

The first moment of the volume distribution in Fig. 4(C), called the volume mean radius $\bar{a}_V$, is thus given by

$$\bar{a}_V = \int_0^\infty a D_V(a)da = \frac{\int_0^\infty a^4 D_N(a)da}{\int_0^\infty a^3 D_N(a)da} \tag{4}$$

whence from Eqs. (1) and (3)

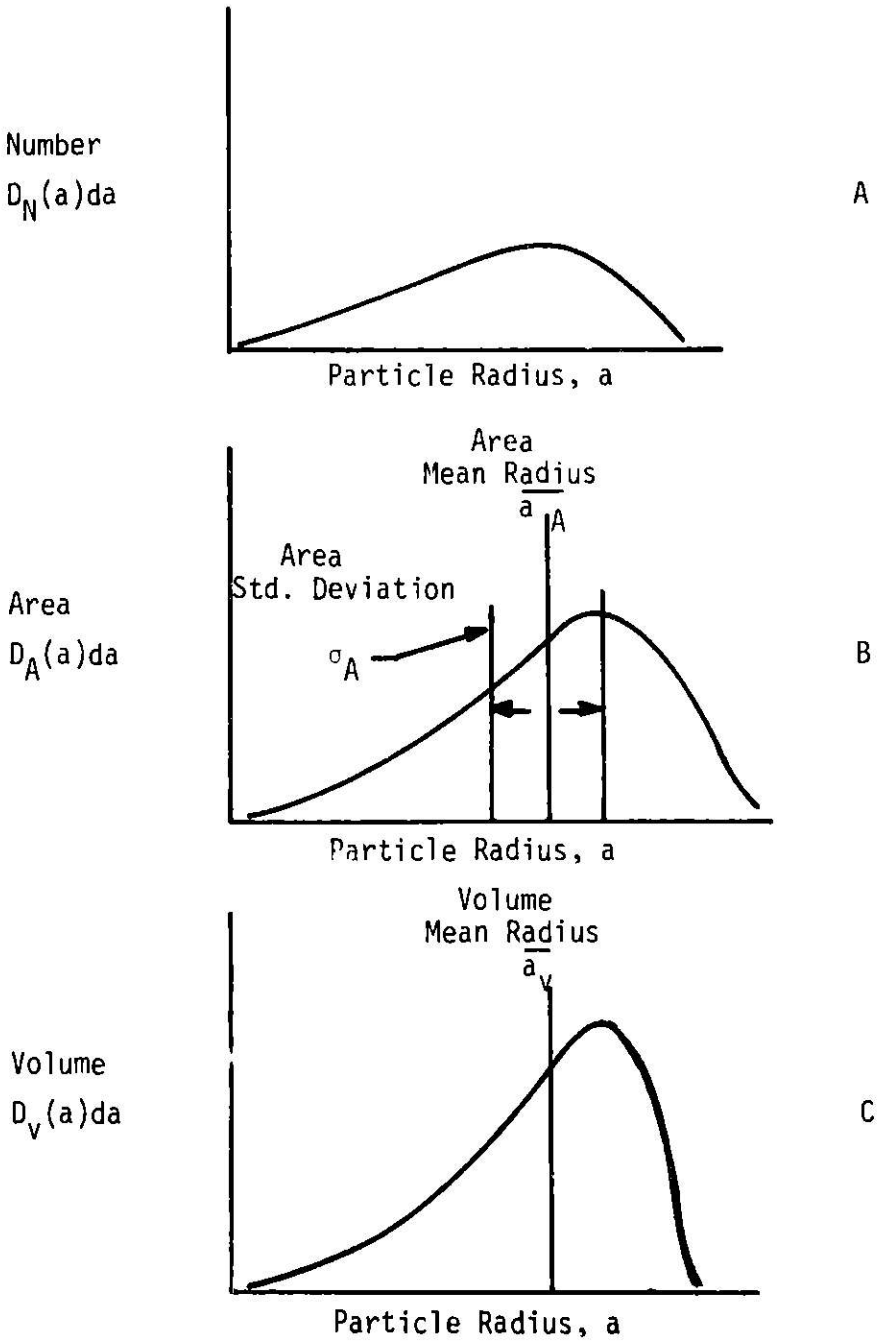
$$\bar{a}_V = \frac{\overline{a^4}}{\overline{a^3}} = \frac{K_3 S_4}{K_4 S_3} \tag{5}$$

Thus the volume mean radius of the particles is given by the ratio of the signals from the fourth and third power apertures, apart from an instrumental constant.

Figure 4

Three Methods of Defining a Particle Distribution:

(a) by number,
(b) by area, and
(c) by volume



This constant depends on the mask design, but it is independent of the intensity of the incident beam. The concentration of the particles does not affect the measurement, so long as it is not high enough to cause multiple scattering.

Another way of describing a particle size distribution is the area distribution $D_A(a)$, where $D_A(a)da$ is the fraction of the total surface area contributed by particles in the range a to a + da. This is shown in Fig. 4(B). From reasoning similar to that used above for the volume distribution, the area mean radius $\bar{a}_A$ is given by

$$\bar{a}_A = \int_0^\infty aD_A(a)da = \frac{\int_0^\infty a^3 D_N(a)da}{\int_0^\infty a^2 D_N(a)da} \quad , \tag{6}$$

whence from Eqs. (1) and (2)

$$\bar{a}_A = \frac{\overline{a^3}}{\overline{a^2}} = \frac{K_2 S_3}{K_3 S_2} \tag{7}$$

Thus, the ratio of the signals from the third and second power apertures gives the area mean radius without the need to monitor the incident beam and it is independent of the particle concentration.

Finally, it is possible to obtain from the three output signals the standard deviation σ_A of the area distribution, which is defined by

$$\sigma_A^2 = \overline{a_A^2} - (\bar{a}_A)^2 \quad . \tag{8}$$

The mean square value of a_A is given by

$$\overline{a_A^2} = \int_0^\infty a^2 D_A da = \frac{\int_0^\infty a^4 D_N(a)da}{\int_0^\infty a^2 D_N(a)da} \tag{9}$$

whence, by Eqs. (2), (3), (5), and (7),

$$\overline{a_A^2} = \frac{K_2 S_4}{K_4 S_2} = \bar{a}_A \bar{a}_V \quad . \tag{10}$$

Thus, from Eq. (8),

$$\sigma_A = \left[a_A(\bar{a}_V - \bar{a}_A) \right]^{1/2} , \qquad (11)$$

which is a measure of the width of the area distribution.

TEST RESULTS

The size range for measurement of particles by the optical scattering method just described is determined primarily by the dynamic range of the instrument's linear volumetric response. Analysis of the mask designed for the ERDA instrument gave a predicted performance as shown in Figure 5. With an ultraviolet laser of wavelength 325 nm, we would expect a uniform response from about 0.8 micrometer (micron) to 50 microns.

The lower size limit is determined by the wavelength of the illumination. As the particle size approaches the wavelength of the light source, the resultant scattering becomes a complex function and deviates rapidly from that which can be interpreted by simple diffraction theory.

The upper size limit for forward scattering measurements is determined by the ratio of scatter signal to optical background that can be achieved. The scattering angles for larger and larger particles approach the laser beam axis and it becomes increasingly difficult to detect the scatter flux signals.

The observed response of the ERDA instrument, as compared to the theoretical response, is shown in Figure 6. The parameters MV, MA and WA are the mean volume diameter, mean area diameter, and standard deviation of the area distribution, respectively. Our initial measurements were made at 325 nm. We obtained measurements on particles as small as 0.8 micron. The deviation factor is the log of the observed response relative to a linear response. The MV and MA functions are well behaved over the range 1 to 50 microns. However, the WA function deviates rapidly above 20 microns.

Unfortunately, the operation of the ultraviolet laser became unstable during the course of our laboratory testing. Its power output variations exceeded the design tolerance of the particulate instrument and the laser unit was returned to the vendor for resolution of this problem. However, acceptable performance could not be achieved in the time scale of our

Figure 5

Volumetric Response vs. Particle Diameter

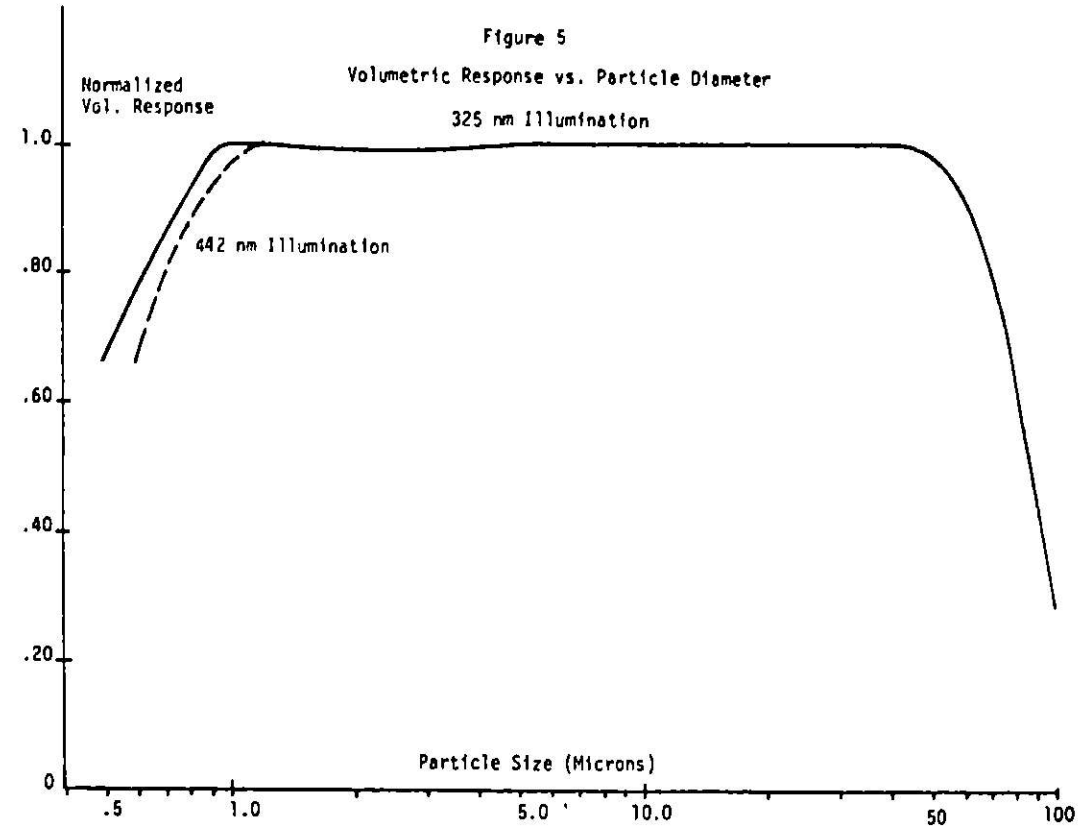
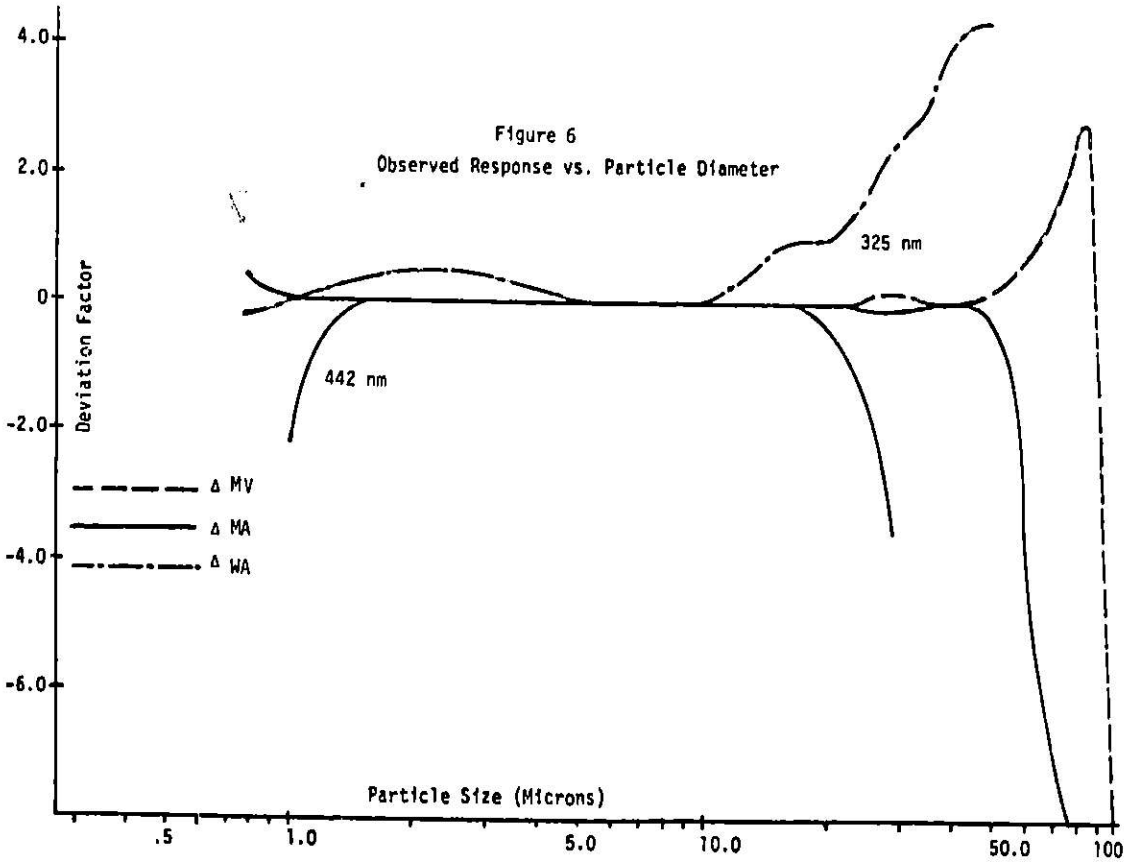


Figure 6

Observed Response vs. Particle Diameter



program. The laser vendor, therefore, recommended that we modify the unit to lase at 442 nm wavelength. After much difficulty we now have a stable laser but operating at the blue wavelength rather than ultraviolet. The observed result for the MA function with this laser is also shown in Figure 6. It yields a uniform response from 1.1 to 20 microns.

A volumetric loading response measured with the instrument as delivered to Argonne is shown in Figure 7. A suspension of diamond dust, of nominal 3 micron diameter particles, was prepared in a water-glycerine mixture. The starting mixture was calculated to be 10 ppm of diamond particles by volume to fluid volume. Then the mixture suspension was diluted by addition of water and glycerine and the volumetric concentration was measured with the ERDA instrument for each dilution. The error bars represent the standard deviation for three repeated measurements at each dilution. The instrument output dV is calibrated in ppm for a one inch path length. For the same equivalent particle loadings in a duct of 10 inches I.D., the threshold for loading measurements would be about 0.02 ppm.

An approximate loading scale in grains/SCF for a product gas at 10 atmospheres and 800°C. in situ conditions is shown on the ordinate of the graph in Figure 7. For these conditions on a 10 inch duct, the equivalent loading sensitivity would be on the order of 0.005 grains/SCF.

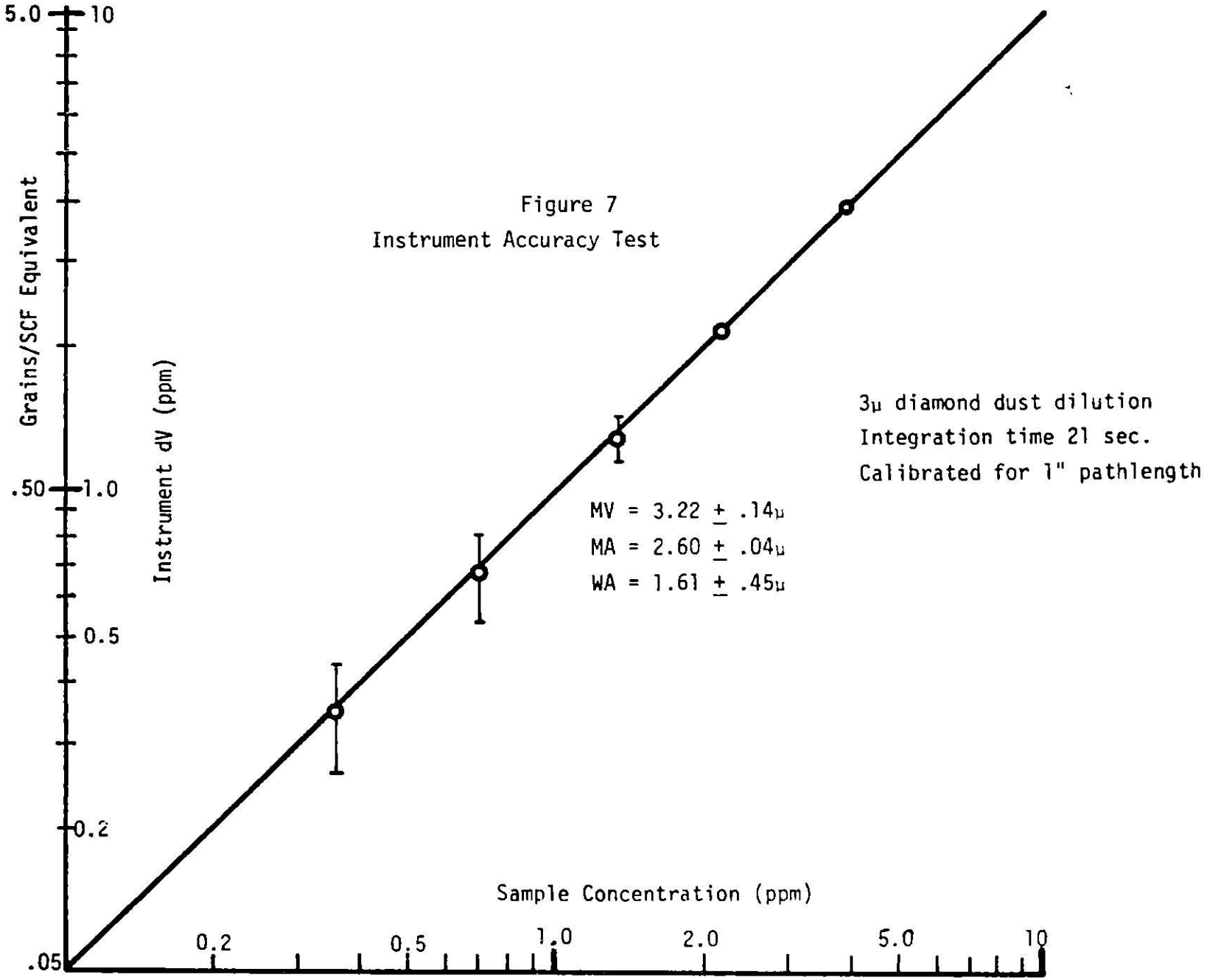
The standard deviations shown for the particle size measurements — MV, MA and WA — are calculated values from all measurements obtained with this diamond dust material. These values agree very well with the material specification.

SUMMARY

An on-line particulate analyzer has been designed for measurement of particles in high temperature, pressurized gas streams. A prototype instrument has been constructed and calibrated. It is now scheduled for operational tests at Argonne National Laboratories and later at Curtiss Wright Corporation.

A summary of the instrument specifications is presented in the following table. The "Achieved" data is what has been observed under laboratory conditions with the prototype unit. The "Forecast" column represents what we believe to be achievable under operating conditions for an improved

Figure 7
Instrument Accuracy Test



instrument having an ultraviolet laser.

PARTICLE ANALYSIS INSTRUMENT SPECIFICATIONS

PARAMETER	GOAL	ACHIEVED	FORECAST
Particle Size Range	0.8 - 50μ	1.1 - 25μ	1.0 - 50μ
Maximum Loading*	100 ppm @ 5μ	100 ppm @ 10μ	100 ppm @ 5μ
Detection Limit*	0.1 ppm	0.2 ppm	0.2 ppm
Sample Path Length	3 - 30 cm	3 - 30 cm	3 - 30 cm
Data Outputs	dV, MA, MV, WA	Same	Same + Histogram

*Data for 2.54 cm I.D. duct

Reference

1. Wertheimer, A. L. and Wilcock, W. L., "Measurements of Particle Distributions Using Light Scattering", Applied Optics, 15, p. 1616, 1976.

QUESTIONS AND ANSWERS

E. S. VanValkenburg

Leeds & Northrup Company

A. C. Tulumello, Delta Scientific

Q. How do you maintain the windows in such a system?

A. We do this by air purge. In the system at Argonne, the air purge scheme was used first for the Spectron Development Lab instrument and we're now using the same scheme on our tests. To date, we have had no difficulty maintaining clean windows with that purge system. Air is directed across the quartz window and maintains a positive pressure in the port sections to keep the particulates confined to the main flow stream of the duct.

W. H. Marlow, Brookhaven National Laboratory

Q. What do you expect the instrument to do in mixed system of opaque and translucent particles?

A. I did not bring up the subject of index from refraction. One of the reasons we have structured the optical system as shown here is to be as independent of index of refraction as possible. However, we have had experience in the laboratory of measuring polystyrene spheres which are quite translucent, even transparent, and we have noted that we get some different data in terms of size and concentration for that type of material as contrasted to diamond dust. We finally ended up using the diamond dust for calibration because we felt it was more typical of material in a gasification gas stream.

D. F. Ciliberti, Westinghouse Research and Development

Q. As one who has frequently suffered through the tedium and uncertainty that are intrinsic to the use of cascade impactors for particle size measurement, I would like to wish you and others in this effort good luck, and as important, good funding.

W. J. Haas, Ames Laboratory

Q. Please describe the alignment and calibration procedure.

A. The alignment procedure is one of adjusting the folding optics to image the laser beam at an optical stop on the mask that I described. We do not want to measure any of the main beam energy by the photo-multiplier, so the alignment procedure is one of directing that beam to that spot, and we have had no difficulty so far in maintaining that alignment in operation. However, I also emphasize that we want to tie the optical

system to the duct, recognizing that the duct is going to move due to thermal effects and pressurization effects. So we want the windows on the duct to track with the instrument, and the accuracy on that still has to be determined from more practical experience. About the calibration procedure...The size outputs are determined inherently by the design of the mask and there is no calibration, beyond that point, required. The only calibration that is needed is on the volumetric response, and that requires that the data be corrected if the laser beam intensity varies. So one of the things we do need to incorporate in future instruments is to make it self-calibrating against the laser beam, providing not just a meter at the back of the instrument as I've shown here, but feeding that signal into the microprocessor so that the laser beam intensity is automatically compensated in the computation. The only other variable is the duct diameter, that is fixed for any installation.

John Modla, Buell Envirotech

Q. Have you tried analyzing scattered radiation of different wavelengths at various angles, e.g., 90° scattering.

A. We have another contract with the Environmental Protection Agency. We use 90° scattering for measuring respiratory size particles, that is, sub-micron sized particles, in stationary stacks. That work will be reported at a later date.

Q. Do you have problems with multiple scattering for particles less than 1 micron?

A. I indicated here that we do need to maintain single event scattering and that does provide an upper bound to the concentration which we can handle. In my last slide I showed that we had achieved measurements at 100 parts per million with 10-micron particles, and as the particles get smaller that limit would have to come down in order to avoid multiple scattering effects.

Q. What is the power output of the laser?

A. The nominal output is of the order of 10 to 20 milliwatts.

Q. Do you plan to extend the capabilities of this instrument in the range of less than 0.5 microns?

A. That relates to the first questions. We are doing that work under an EPA contract.

J. Trolinger, Spectron Development Lab. Inc.

Q. What calibration tests have been performed for non-spherical particles?

A. We have done no work specifically on non-spherical particles in the laboratory. We have done particle analyses on elipsoids of revolution, and anticipating that if you have elongated particles, they will be mixed with spherical particles in a random orientation. We do not consider shape in this application to be any problem.

Q. How is the sample volume defined?

A. The sample volume is defined by that portion of the laser beam that is resident inside the duct. We would like to measure all of the particles in that volume. There is one constraint and that is the collection lens. As the path length gets longer and the particles get smaller, the smaller particles scatter in wider angles. The lens, in that case is not going to catch all of that energy. So what we've set up is a criteria that is to measure to the midpoint of the duct, as a minimum for all sizes of particles, and then we compensate the mask structure for those small particles that are beyond the midpoint. This anticipates that if there is non-homogeneity of the particles, they should hopefully have some radial distribution across the duct.

Q. Is it size dependent?

A. The sample volume is not dependent on size. It is dependent strictly on the laser beam dimensions.

F. Bondy, Foster Wheeler Energy Corporation

Q. Is the maximum allowable dust loading for gas turbines 0.01 grams per standard cubic foot or 0.01 grams per ACF?

A. The data that I showed in my last slide was calculated for standard cubic feet for a fluidized bed system operating at 10 atmospheres and 1500°F temperature. The pressure temperature conversion for standard conditions that I showed on the chart gives a limit of 0.01 grain/scf for a ten-inch duct on a typical fluidized bed pressurized system.

REQUIREMENTS FOR ON-LINE COMPOSITION ANALYSIS OF COAL GASIFICATION PROCESS STREAMS USING OPTICAL METHODS

J. V. Walsh
C. F. Braun and Company
Alhambra, California

REQUIREMENTS FOR ON-LINE COMPOSITION ANALYSIS OF COAL GASIFICATION PROCESS STREAMS USING OPTICAL METHODS

J V Walsh
C F Braun & Co
Alhambra, California

ABSTRACT Adaptation of instruments using radiation may answer the need for composition analyzers in coal gasification process streams. Such instruments would use radiation in the range of 200 NM in the ultraviolet to 15 μM in the infrared. The use of both emission and absorption principles has been widely used in process applications and should be adaptable to the analytical and environmental constraints of the coal-related processes. The principal components of interest are steam, carbonyl sulfide, and oxides of nitrogen, carbon and sulfur, hydrogen sulfide, oxygen, methane, hydrochloric acid, and total hydrocarbons. Requirements for these analyzers are reviewed in detail.

I INTRODUCTION

For the purposes of this presentation, under the heading of optical methods are grouped instruments using invisible as well as visible radiation in the range of 200 NM in the untraviolet to 15 μM in the infrared. The principles involved and the techniques available for the transmission and collection of energy are essentially similar throughout the range. Figure 1 shows the electromagnetic spectrum in broad terms and the relationship of the units used for wavelength. Traditionally, the regions under consideration are near ultraviolet (200 to 400 NM), the visible (380 to 750 NM), and the infrared (1-15 μM).

When this radiant energy passes through gases or liquids, some of it is absorbed by the molecules. The energy absorption is a function of wavelength. A measurement of this absorption is referred to as a spectrum and can be determined for any gas or liquid. Molecular concentrations are determined by measuring the energy absorbed in a given path length. This absorption process approximately follows Beer's law. This expression is shown in Figure 2. This principle has been widely used in both laboratory and process applications for many years.

Figure 3 is a list of some compounds analyzed by optical methods. Obviously it is a partial list, but it does contain most of the substances relevant to this discussion. Another reason for showing the list is to point out the traditional separation of the IR AND UV/VIS. The availability of detector systems in the past has resulted in a natural division. The evolution of instrumentation and detector technology in recent years has all but removed the need for the separate categories. This point will be addressed in greater detail later.

II INSTRUMENTATION REQUIREMENTS

It would be impractical to set forth the detailed specifications for all of the optical analyzers that might be applied in coal gasification processes. As an alternative to this, generalized requirements will be presented. This applies to both analytical needs and analyzer performance. Figure 4 gives typical low-level ranges. It will be noted that carbon dioxide is shown at 0-15 percent. While this may be typical, 0-40 percent would appear quite commonly as a stream concentration. Hydrogen, carbon monoxide, carbon dioxide, methane, nitrogen, and water vapor are components falling in the range of 10 to 90 percent.

The analysis of these components may be required for control or material balance purposes. It is stated that these may be required because, obviously, a final analytical method has not been chosen.

Typical analyzer performance is given in Figure 5. These requirements appear to be compatible with most instrumentation available in today's marketplace. This figure does not take reliability into consideration. Historically, process analyzers are not particularly reliable. This reputation may endure for decades after it is no longer true. There are indications that reliablility is becoming a reality and that ninety days of operation without component failure is becoming commonplace. This is encouraging, since ninety days appear to be the goal that would satisfy most end users.

III OPTICAL ANALYZERS

A textbook description of an analytical optical analyzer would probably be that of a prism or grating instrument. Figure 6 shows the optical schematic of a commercially available device. Such instruments are expensive, complex, and fragile.

They are inherently incapable of meeting the analyzer requirements that have previously been set forth.

This type of instrument depends on the dispersion of light from the surface of a replicate grating or prism. The use of a narrow slit produces essentially monochromatic radiation which passes through a sample volume. After passing through the sample absorption cell, the radiation is focused on a detector and the electrical signal produced is amplified and displayed or recorded by conventional means. The resolution of these instruments is a function of the dispersion of energy.

This point is made because the instruments of most probable interest operate in an opposite manner. Figure 7 shows a nondispersive infrared analyzer. There are many variations of this device, but they all act in essentially the same way. The availability of highly selective filters has made these devices possible. Their simplicity, low cost, and reliability has made them attractive for process applications. These filters are capable of passing extremely narrow portions of the energy radiated from a source such as a tungsten filament. Passbands of 0.05 micron or better in the infrared are readily achievable. Thus, the energy transmitted through the sample cell is equivalent to that achieved by a prism or grating instrument.

It should be noted that numbers of such filters can be located on a rotating disc, and can thus provide greater analytical capability. The detectors used on such instruments come in many forms but always depend on the absorption of energy for their operation. Figure 8 shows a similar analyzer using a solid state detector. The essential difference is that the filtering takes place after the radiation has passed through the sample.

To this point it has been implied that this approach to analyzer design is limited to infrared devices. The solid state detectors mentioned are compact, reliable, and have rapid responses. The higher the frequencies that are used to modulate the detectors, the simpler the electronics become. These detectors have an extremely useful parameter, which is the detectivity (D*). This is a figure of merit and is the reciprocal of the product of the noise equivalent(1) power and the square root of the detector area. Thus $D^* = Vs \ (A\Delta f)^{1/2} / Vn \ W$.

(1) Noise equivalent power is defined as the rms value of the radiant power producing a signal equal to the noise measured at a specified wavelength, or black body, plus radiation at a particular temperature, chopping frequency and bandwidth.

Where Vs and Vn are the signal and noise voltages, A the area, f the bandwidth of the amplifier, and W the rms radiation power following on the detector. The variation of D* with wavelength for a number of detectors is shown in Figure 9. The effects of temperature are quite apparent. Of particular interest, however, is the pyroelectric detector at ambient temperature. The essentially linear response throughout the ultraviolet, visible, and infrared regions makes broadband analyses with a simple instrument quite practical.

IV PROCESS STREAM ANALYSIS

The purpose in providing an analyzer on a coal gasification process stream is twofold. The analysis of the gaseous components of the process stream is as important as in any production process. The second purpose is a material balance. In these processes the sampling frequencies are high enough to make individual analysis undesirable. Figure 10 shows the distribution of concentrations for five processes. These figures represent the analysis prior to methanation. All of the major components in all of the processes are at concentrations that do not usually result in analytical problems.

Figure 11 shows the concentrations after methanation. Again, the analysis is essentially straightforward with some difficulty involved in the low level of the carbon monoxide concentrations. It is presumed that the low-level concentrations would be accomplished with analyzers of a design somewhat different from those used for the major components. To accomplish both tasks with the same instrument would seem to be an unnecessary and counterproductive constraint.

Another example of an on-line analysis is shown in Figure 12. The concentrations shown are post-sulfur recovery in a stream using Eastern coal. This is typical of a flue gas application. Instrumentation for this analysis does exist in several forms. Figure 13 shows an estimate of the concentrations in the CO_2 absorber feed gas at relatively high pressure. The gases here would again imply the use of two separate instruments. This is the hydrogen sulfide removal section. The analysis of H_2S is of particular importance. However, the analysis of the others is required.

V CONCLUSION

In looking at the requirments for on-line composition analysis using optical methods, several points have been emphasized. The first is that the UV/VIS/IR part of the electromagnetic spectrum is so narrow that with detection devices available today, there no longer exists any fundamental reason for using separate instruments. This approach would provide a single instrument capable of performing a material balance at a rapid rate. The quality of the analysis would be inherently greater than that provided by separate analyzers.

The performance requirements are essentially the same as most process instruments available in the market place. Review of the process stream compositions shows that there are no unusually difficult analyses if the use of separate instrument designs for high-and low-level applications is accepted. It is believed that analytical instruments that would meet the requirements set forth are well within the current state of the art.

FIGURE 1

THE ELECTROMAGNETIC SPECTRUM
WAVELENGTH UNITS

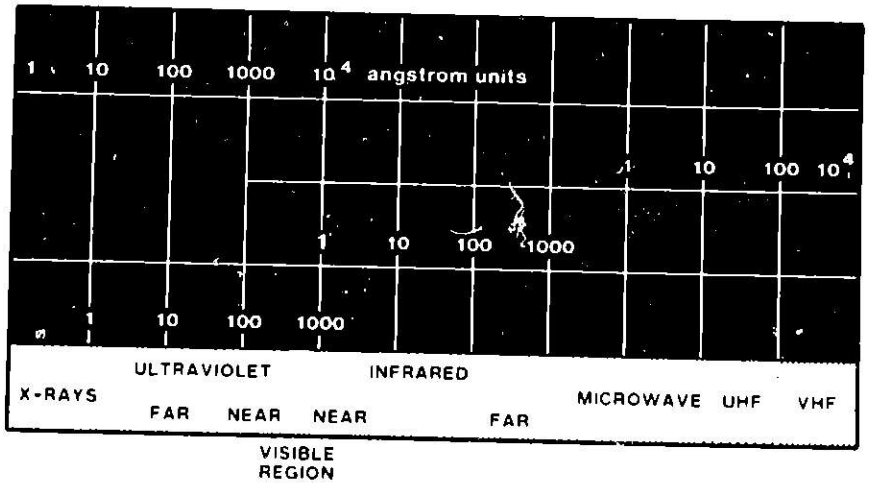


FIGURE 2

BEER'S LAW EQUATIONS

$$I = I_o e^{-\alpha CL}$$

OR

$$\text{Log } \frac{I}{I_o} = -\alpha CL$$

TRANSPOSING: $$C = \frac{\text{Log } \frac{I}{I_o}}{\alpha L}$$

WHERE α = ABSORPTION COEFFICIENT
C = MOLECULAR CONCENTRATION
L = PATH LENGTH

FIGURE 3

COMPONENTS ANALYZED BY OPTICAL ABSORPTION METHODS

THIS IS A PARTIAL LIST OF SUBSTANCES NORMALLY ENCOUNTERED IN ANALYTICAL APPLICATIONS.

	IR	UV/VIS
COMPONENTS COMMONLY MEASURED (IN APPROXIMATE ORDER OF IMPORTANCE)	CO CO_2 CH_4 C_2H_2 C_2H_4 H_2O N_2O NO NH_3 $COCl_2$ ETHYLENE OXIDE C_2H_6 C_3H_8	Cl $COCl_2$ SO_2 NO_2 F_2 O_3 Hg
COMPONENTS WHICH ALSO ABSORB	ALL ORGANIC COMPOUNDS SF_6 HCN NO_2	AROMATIC HCs HALOGENATED HCs UNSATURATED HCs WITH CONJUGATED DOUBLE BOND CS_2 COS CCl_4 ClO_2 H_2S $Ni(CO)_4$ Br_2
COMPONENTS WHICH ABSORB WEAKLY	H_2S HCl N_2H_4	
COMPONENTS WHICH DO NOT ABSORB	$H_4N_2O_2$ A INERT GASES Cl_2F_2	SATURATED HCs UNSATURATED HCs WITH ONE DOUBLE BOND ALCOHOLS ETHERS HC

FIGURE 4

LIST OF COMPOUNDS AND TYPICAL RANGES

COMPOUND	RANGE (PPM)*
NO	0-25
CO	0-500
CO_2	0-15%
SO_2	0-25
H-C	0-25
H_2S	0-100
H_2O	0-1000
NO_2	0-100
NH_3	0-100
HCl	0-100

*UNLESS OTHERWISE NOTED

FIGURE 5

TYPICAL ANALYZER REQUIREMENTS

ACCURACY	±2%
LINEARITY	±1%
ZERO DRIFT	±2% / 90 DAYS
SPAN DRIFT	±2% / 90 DAYS
SYSTEM RESPONSE	(1/e) 1 SEC.
OUTPUT TO RECORDER	4-20 ma, 10-50 ma (FULLY FLOATING OR GROUNDED LOOP), 0-1V
TEMPERATURE	-40 TO 150°F
LINE VOLTAGE	115 ±10%

FIGURE 6

PRISM SPECTROMETER

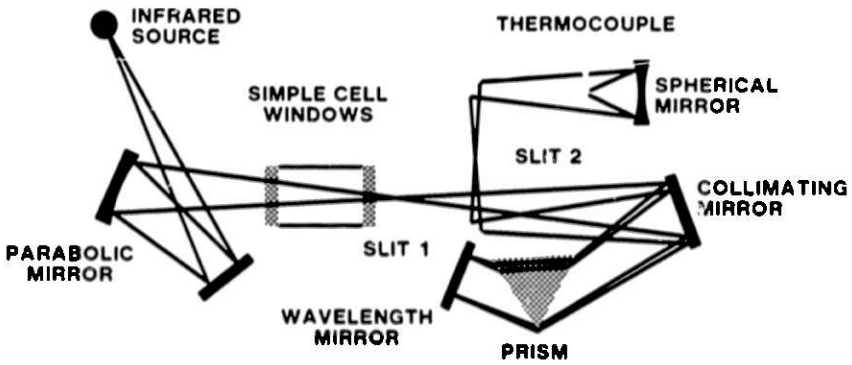


FIGURE 7

NDIR ANALYZER - LUFT DETECTOR

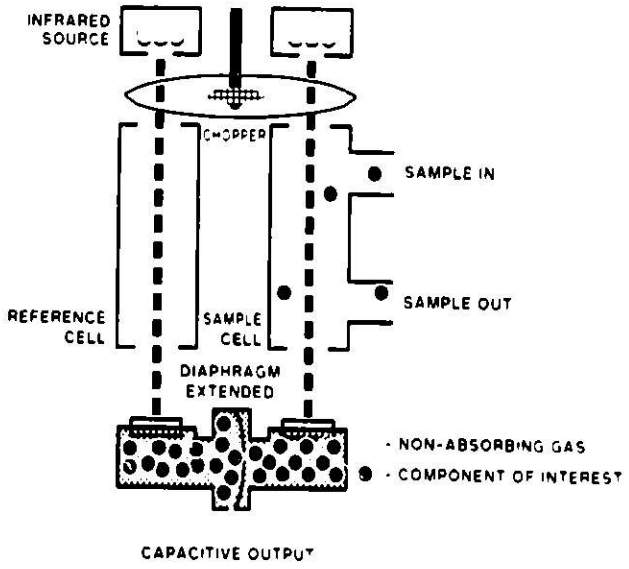


FIGURE 8

NDIR ANALYZER-SOLID STATE DETECTOR

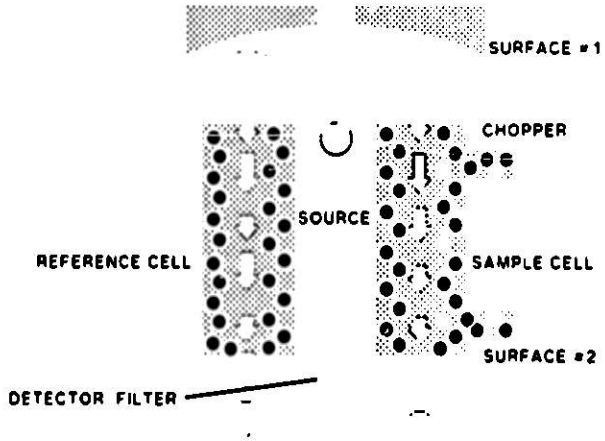


FIGURE 9

SPECTRAL SENSITIVITY CURVES OF VARIOUS DETECTORS

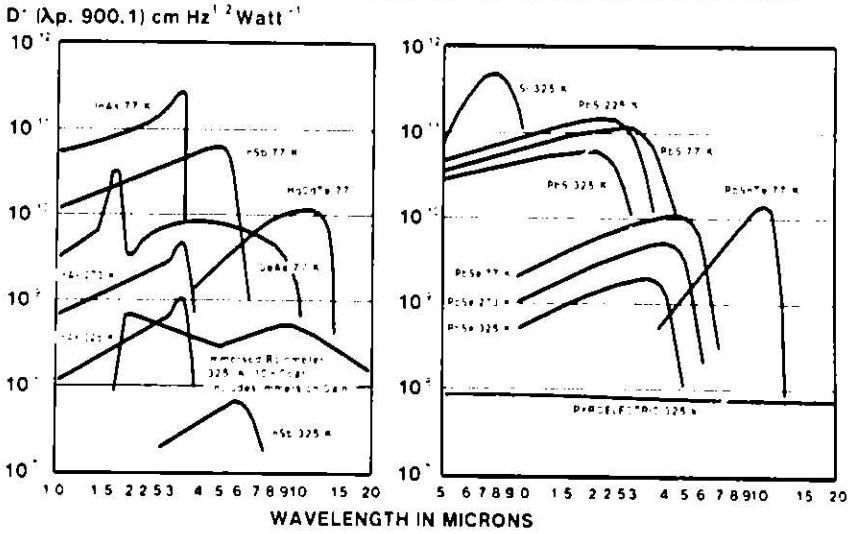


FIGURE 10

RAW GAS QUENCH (WESTERN COAL) QUENCHED GAS (TO SHIFT CONVERSION, ACID GAS REMOVAL)

MOL % BY PROCESS

	BI-GAS	LURGI	SYNTHANE	CO_2 ACCEPT	STEAM-Fe HYGAS	STEAM-O_2 HYGAS
H_2	19.66	-	14.82	63.89	51.17	18.11
CO	14.51	-	8.20	15.44	14.78	15.22
CO_2	17.04	-	26.40	5.14	6.19	15.23
CH_4	8.81	-	9.17	14.50	24.06	10.42
COS	.01	-	TRACE	TRACE	.01	.01
H_2S	.14	-	.19	.03	.20	.17
NH_3	.20	-	.49	.09	-	.27
N_2	.11	-	.12	.25	1.22	-
H_2O	39.52	-	39.30	.67	.10	39.39
OTHER	-	-	$C_2H_6C_6$ OIL 1.29	-	$C_2H_6C_6$ 2.27	$C_2H_6C_6H_6C_7$ 1.18
P PSIG	1,185	-	980	130	1,115	1,185
T°F	456	-	443	100	100	461

FIGURE 11

METHANATION (WESTERN COAL) PRODUCT GAS

MOL % BY PROCESS

	BI-GAS	LURGI	SYNTHANE	CO_2 ACCEPT	STEAM-Fe HYGAS	STEAM-O_2 HYGAS
H_2	9.96	9.69	12.95	11.31	9.75	11.70
CO	.10	.05	.09	.10	.09	.09
CO_2	2.64	3.18	1.08	3.66	1.63	1.55
CH_4	86.61	85.91	85.11	84.22	86.09	86.57
N_2	.59	1.07	.68	.63	2.35	-
H_2O	.09	.09	.09	.09	.09	.09
T°F	100	100	100	100	100	100
P PSIG	1,017	1,017	1,022	1,017	1,037	1,017

FIGURE 12

PRELIMINARY ESTIMATES OF TYPICAL COAL GASIFICATION PROCESS (EASTERN COAL)

TEMPERATURE 250 °F
PRESSURE 0.1 PSIG

SPECIES	LB-MOLS/HR	MOL%
H_2	-	-
O_2	3,351	2.19
CO	-	-
CO_2	23,255	15.18
SO_3	-	-
SO_2	70	.05
CH_4	-	-
COS	-	-
H_2S	-	-
NH_3	-	-
N_2	105,557	68.90
H_2O	20,466	13.36
TOTAL	153,199	100

STREAM NAME: FLUE GAS TO STACK

FIGURE 13

PRELIMINARY ESTIMATES OF TYPICAL COAL GASIFICATION PROCESS

(EASTERN COAL)

TEMPERATURE 80 °F
PRESSURE 1,115 PSIG

SPECIES	16- MOLS /HR	MOL%
H_2	15.248	48 08
O_2	-	-
CO	4 676	14 74
CO_2	11.554	36 43
SO_3	-	-
SO_2	-	-
CH_4	8.251	26 02
COS	1 9	0*
* H_2S	0 1	TPACE
NH_3	-	-
N_2	-	-
C_2H_6	261	82
H_2O	3	01
TOTAL	39.995	100

STREAM NAME: CO_2 ABS FEED GAS

TODAY AND TOMORROW IN REFINERY CONTROL

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Today and Tomorrow in Refinery Control

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Abstract

This paper describes the features of the control systems and instrumentation of a modern petroleum refinery. Illustrations are based on the Sohio-BP refinery at Marcus Hook, Pa. which was recently modernized. The paper also presents some projections into the future and a philosophical approach to solving existing problems and attaining better control for the future.

Introduction

The modern petroleum refinery has adopted many of the recent advances in control technology. The Sohio-BP Refinery at Marcus Hook, Pa. was recently modernized and will be used to illustrate the features of a current control systems design in this industry. A list of refinery control objectives is shown in figure 1. Whatever new or innovative systems we are applying should reflect in meeting these goals.

Although progress is being made in many areas, there are still problems which lack a satisfactory solution. We as managers, engineers, teachers, and technicians should be able to find these solutions. However, there are credibility gaps that exist between us which we must overcome in order to solve the problems and have better control in the future.

The 1975 Refinery Control System

The Sohio-BP Refinery at Marcus Hook was recently modernized by the addition of several new process units and the revamp of some of the existing units. Figure 2 is a list of features of the control systems in a modern refinery. They are primarily based on the Marcus Hook project.

Early in the project, a comprehensive study was made to develop a plan for overall refinery control. The plan called for one central control room, not only for the new facilities but also a consolidation of the existing local control rooms. The modern refinery has considerable process integration and the common control location improves communications,

simplifies data acquisition, and reduces manpower. New refineries are being built with centralized controls and a few older plants are consolidating their various unit control rooms into one common control center. Sometimes, off-site facilities such as gasoline blenders are also controlled from the central control room.

The Marcus Hook Refinery Control Center floor plan is shown in figure 3. The building is 114 feet by 73 feet overall with the control room occupying about one-half the total space. The control room provides for approximately 200 linear feet of panel. The panels face to face are 20 feet apart in the narrow direction. The building also provides a computer room, offices, locker facilities, analyzer room, switchgear room, and mechanical equipment room. The analyzer room contains laboratory type chromatographs which are computer-controlled. The shift supervisor's office is flush with the panel where it becomes part of the control room. Computer type flooring is provided in the computer room and behind the panel plus crossovers in the control room. Figure 4 is a photo taken inside the control room. Emergency lighting, battery powered, is provided. Also a closed circuit TV monitor to allow the operators to watch the relief gas flare stack is provided. The operator consoles are located symetrically in the room and over the cable trenches.

The control room shown in the figures has 4 board operators with about 110 to 160 control loops each. By comparison, most single unit control rooms, will have 25 to 50, maybe a few as high as 75, control loops with a full time board operator.

Control loops are defined to include a transmitter, panel mounted controller, and final control element on the process.

About 100 control loops per board operator represents current good practice in a refinery control center. If you are significantly below this level then you have a problem. With special digital scanning techniques and operator training, the 200 to 300 level may be attained.

Due to longer transmission distances, computer compatibility, and past experience, there is a general preference for electronic instrumentation. Figure 5 shows the front of panel arrangement for this type of instrument. The panel shown is a semi-graphic type with the alarms incorporated into the graphic section. A page-talk intercom system with multiple channels is provided for communication to the field. This communication system is supplemented with Walkie-talkies. There are no large case multipoint recorders. Each section of panel has a patch-board trend recorder included with the shelf instruments. Dedicated recorders are minimized. Generally less than half of the control loops have recorders. Some plants have reduced this to near zero by utilizing computer monitoring and logging capabilities. Thermocouples have a digital readout on the console. Standby control stations for manual takeover, are provided on the panel front in case of a controller failure.

The rear of the panel is shown in Figure 6. All auxillary equipment is installed in the rack against the wall. There is four feet of clear working space between the rack and the panel. All interconnects between the rack and the panel or the computer are by cord-set with a plug on each end and looped under the raised floor. Redundant DC power supplies and alternate AC power sources with automatic transfer are provided. The rack also contains integral computer interfacing equipment. This arrangement allows maximum shop checkout and minimum field hookup time. It should become common practice in several years. The wiring to the field

is run underground for fire protection. Intrinsically-safe type installations have not been generally adopted so far.

Computer control is operator oriented and generally supervisory rather than DDC. Supervisory control is less expensive than DDC when the majority of the control loops require analog backup as in a refinery. Typically, 85% of the control loops work well with conventional analog control. Therefore, only about 15% of the control loops can be justified for computer control. However, the computer needs inputs for all the data for operator information displays such as graphic CRT's. Figure 7 is a typical computer-based CRT graphic display. These have proven to be very popular with the operators. The computer facilities are in a separate room in the control center with only operator consoles and typewriters in the control room. The computer room is shown in Figure 8.

The computer installation is generally a joint effort of central staff and plant personnel. The on-going support work is the responsibility of the plant organization and primarily done by chemical engineers. Considerable use is made of vendor capabilities in supplying computer control technology. However, the available skills in this area are generally not as good as advertised. Process computer outages do occur. Computer maintenance contracts are normal practice and the service is generally good. Limited applications for programmable controllers have been found in the refinery. These include catalyst regeneration systems, dryer switching, and various package units requiring sequential operations which are repetitive.

Today's refinery will also likely have special systems utilizing small computers. These may be part of a package such as an octane monitoring system for an automatic gasoline blender. Another typical system is computer-controlled chromatographs with full spectral analysis. The digital equipment for these applications is likely located in the control center. In the Marcus Hook control center, the octane monitoring system includes a minicomputer, but the chromatographs are controlled by the large main computer system. Octane, incidently, is on closed loop control, whether leaded or unleaded.

With the high cost of construction labor, considerable savings has been realized thru the use of field multiplexing of instrument signals. The cost of wiring cables is also greatly reduced. Thermocouples, which are not on control, are a ready application. Refineries have several hundred of these points. Systems include digital readout in the control room and computer interfacing. Another application is the remote multiplexing of discrete or status information, such as alarms, running lights, valve position indicators, and start-stop switches. An automatic gasoline blender has been installed in this way, however, a much higher speed system is required here than in the case of the temperature points. A blender control panel is shown in Fig. 9. The order of magnitude of savings for these multiplexing systems over hardwiring is hundreds of thousands of dollars.

Another practice, becoming standard in the refinery, is the installation of vibration monitoring systems for all major centrifugal compressors and turbines. These may even include automatic shutdowns, especially on axial measurements. Dual sensors are being used to avoid false trips.

The present day refinery will also save money by installing full block and bypass manifolds around only those control valves where it can be justified. Some plants have over 15 years of satisfactory operating experience with a "minimum block and bypass practice." The experienced design team can do an excellent job of selecting those applications where you expect to have problems or are extremely critical. About 30% or less of the total installations will require full manifolds in a refinery. Another 20% may have partial manifolds such as only one block, upstream or downstream, blocks and no bypass or a bypass with no blocks. At least 50% will be in clean, low pressure drop, routine applications with no blocks and bypasses. One in five of these may have handwheels and the remainder installed with only a three-way valve in the signal line at the diaphragm for connecting a temporary air supply.

There seems to be an increased use of on-stream analyzers. The full spectral chromatographs already mentioned is one example. Other examples include stack gas O_2 monitors on heaters and boilers for energy conservation and "oil in water" detectors for environmental protection. Computers are even calculating furnace efficiencies with on-line data which includes the oxygen analysis. The new probe type O_2 analyzer has been widely accepted because it is simple in operation and easy to maintain.

Refineries have had outstanding safety performance for many years. Today's plant has higher pressure processes. For this reason and others, central control rooms are being built with blast resistant construction and no windows. More extensive testing is being done to insure against leaks in the process instruments, lead line connections. The fullest attention is

given to providing explosion proof installation of electronic devices and wiring. Gage glasses are being restricted to low pressure applications only; such as under 1000 psig. Metal tube level gages or back up instruments are used in the high pressure services. Our experience to date with the features just described has been good and they have brought us a long way toward reaching the goals listed in figure 1.

Trends to the Future

The major advancements of the next 5 to 10 years will likely continue to be in the control center area. Developments are trending toward the replacement of the traditional control panel and its analog display instruments with operator consoles utilizing multiple CRT's.

This concept has been proposed in the literature for at least a half dozen years so more people are getting used to the idea. Operators are spending more time away from the panel with their present vintage computer consoles. Related industries are on the verge of trying this approach. Instrument companies seem to be pointing in that direction with new hardware packaging arrangement. When it has been proven in actual practice, the refineries will be ready to consider it. The main incentives are greater manpower efficiency and fast response to minimize upsets. The main drawback would seem to be that it restricts support personnel from sharing the load in an emergency.

Other projections are:

1. Field multiplexing of signals will be expanded to include control loops.
2. Process units will have standard control packages. These will likely include monitoring startup and shutdown procedures, with alarms when the proper step is not followed.

3. Optimizing systems will be developed to quickly adjust control strategies based on changing feedstocks or equipment limitations.
4. Board operators will be upgraded to become a part of the decision making team.
5. The majority of flow measurements will continue to be orifice meters, however, electronic-balance type transmitters will probably replace the force-balance type.
6. Increased use of throttling ball valves is likely. Only the cage type valve, of recent innovations in control valves, has become generally accepted. Butterfly type control valves, with 90° travel, have also gained greater use.

Reducing the Credibility Gaps

Now that we have reviewed the achievements of today and made some predictions for tomorrow, let's look at some of today's problems and their solution. Implementing closed loop computer control is still not a reality in many cases. Only the most outstanding plants exceed 85% service factor for on-stream analyzers. Tubeskin thermocouples have questionable accuracy and reliability. Tank gaging systems need updating. Some instruments are susceptible to radio frequency interference and lightning damage. We are still looking for a satisfactory way to measure flare gas flow rate. How are solutions to these and other problems going to be discovered and developed?

We each have our own realm of understanding and expertise. People with whom we contact in our work see things differently than we do. This may be due to poor communications, varying experiences, prejudices, etc. The result is a so-called credibility gap. This can be illustrated by the following experience.

In choosing an instrument supplier for a project a few years ago, we decided to include in the selection criteria - the ability to apply advanced control schemes to the process. Proposals were received and since the process was licensed to us, the licensor was asked to comment on the proposals. They were all rejected as unjustified. That, is a credibility gap.

These gaps seem to exist between all of us: manufacturer and customer; contractor and client; design engineer and maintenance; universities and industry; process and control systems; and management and computer staff.

We can reduce these credibility gaps and make the best use of our talents to advance the technology if several things happen:

1. The instrument engineer and the process engineer must understand each other. The hardware should fit the process and serve one of these functions; control, safety, equipment monitoring, and/or accounting.
2. Operating personnel must be able to interface their process thru the control system. Board operators should be given increased latitude in making choices of alternate actions.
3. Instruments and systems must be capable of being maintained easily and rapidly. The design person should find out what doesn't work and the maintenance person should be able to learn new techniques.
4. Instrumentation must be produced on the basis of the latest proven technology, at a reasonable price, and without adverse side effects. Service should be prompt and qualified.
5. The academic institutions must relate the theory to practice so that the learner easily becomes a doer and uses all the proper tools.

6. Engineers and managers must see through the mistique of computers so that their use also serves one or more of these functions; control, safety, equipment monitoring, and accounting.
7. Contractors must be flexible enough to accept and follow the preferred practices of the refiner. The refiner should have an up-to-date set of control systems specifications and instrument standards.

Much of this is being done today. People are communicating with each other. There are many educational opportunities available. Control practice is becoming better documented. The Instrument Society of America and the American Petroleum Institute have made good progress recently in the publication of new and revised recommended practices and standards. These are not stand-alone documents in most cases, however, they are excellent supplements to individual company specifications and project criteria. In the area of training, the latest technique is videotapes. Some are available for purchase and some organizations are also producing their own.

There are available today, several instrument engineering service organizations. Often part of a vendor organization, they are highly capable in such areas as construction engineering, field supervision, analyzer system design, shop fabrication and calibration. Greater use is being made of these capabilities.

Also, Management is more aware of the role of the control systems today and thus control systems are more a part of overall refinery control. This managerial loop is broadening, which means better automation decisions are being made. The refining industry is a leader in the application of new control technology. The modern refinery is being built for maintenance accessibility, reliability and with good documentation.

In closing, here are a few suggestions for creating better working relationships and doing a better job in the future:

1. Think about how you are affecting the ability of others to do their job. Put yourself in their shoes.
2. Everytime you do a job - try something new.
3. Emphasize what you do best.
4. Remember the proverb, "What thy hand findeth to do, do it with thy might."

It has often been said that instrument people stick together. In these days of inflation and the energy cruch, it seems even more important than ever, for us to work together in reducing the credibility gaps to make our contribution to the profitability of our employers and to the improvement of our environment.

Figure 1

Refinery Control System Objectives

1. Close control, Minimum Deviation from Plan.
2. Smooth Operation, Few Upsets, Fast Response.
3. Reliability, Long Life.
4. Safety for personnel and equipment.
5. Low cost, easy to maintain.
6. Manpower efficiency, more loops per operator.
7. Accurate data, readily available, current.
8. Optimization, Adaptability.
9. Standardization.

Figure 2

Modern Refinery Control Systems Features

1. Centralization, Consolidation
2. Electronic Instrumentation
3. Computer Control
4. Graphic CRT's
5. Programmable Controllers
6. Computer Controlled Chromatographs
7. Octane Monitoring Systems
8. Remote Multiplexers
9. Vibration Monitors
10. Minimum Control Valve Manifolds
11. On-stream Analyzers
12. Safety Instrumentation

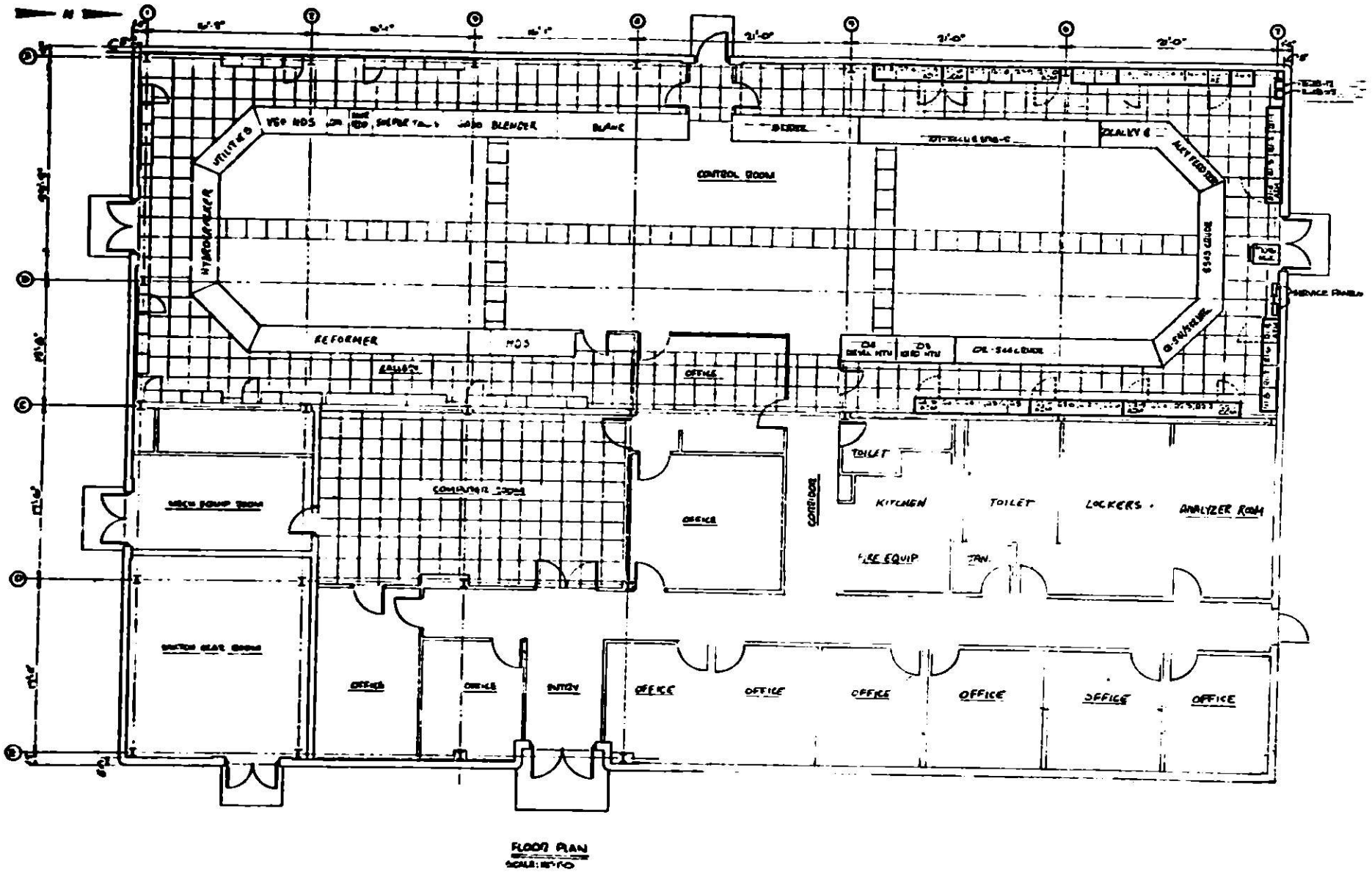

Fig. 3. Modern Refinery Control Center Floor Plan

Fig. 4. Control Room

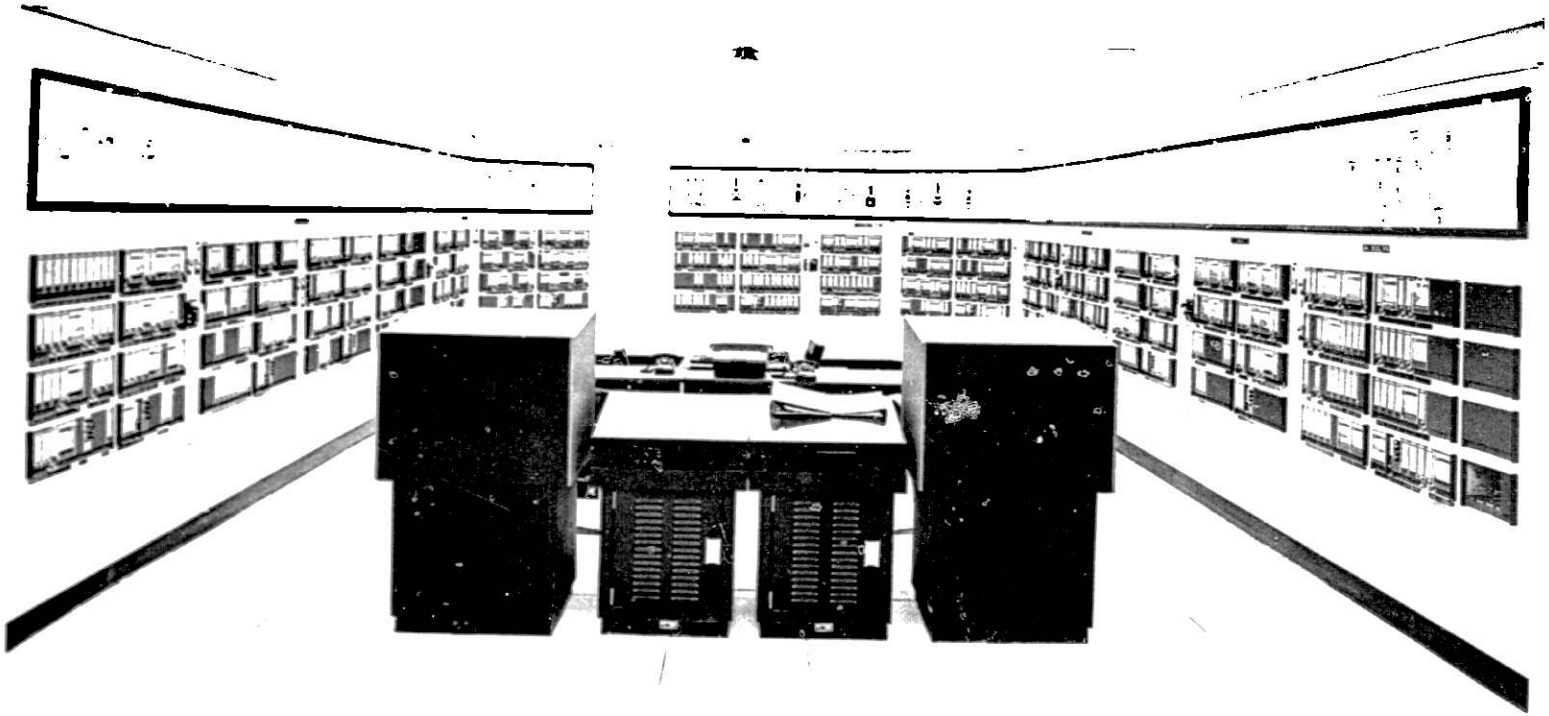

Fig. 5. Instrumentation Panel Arrangement

Fig. 6. Rear View of Instrumentation Panel

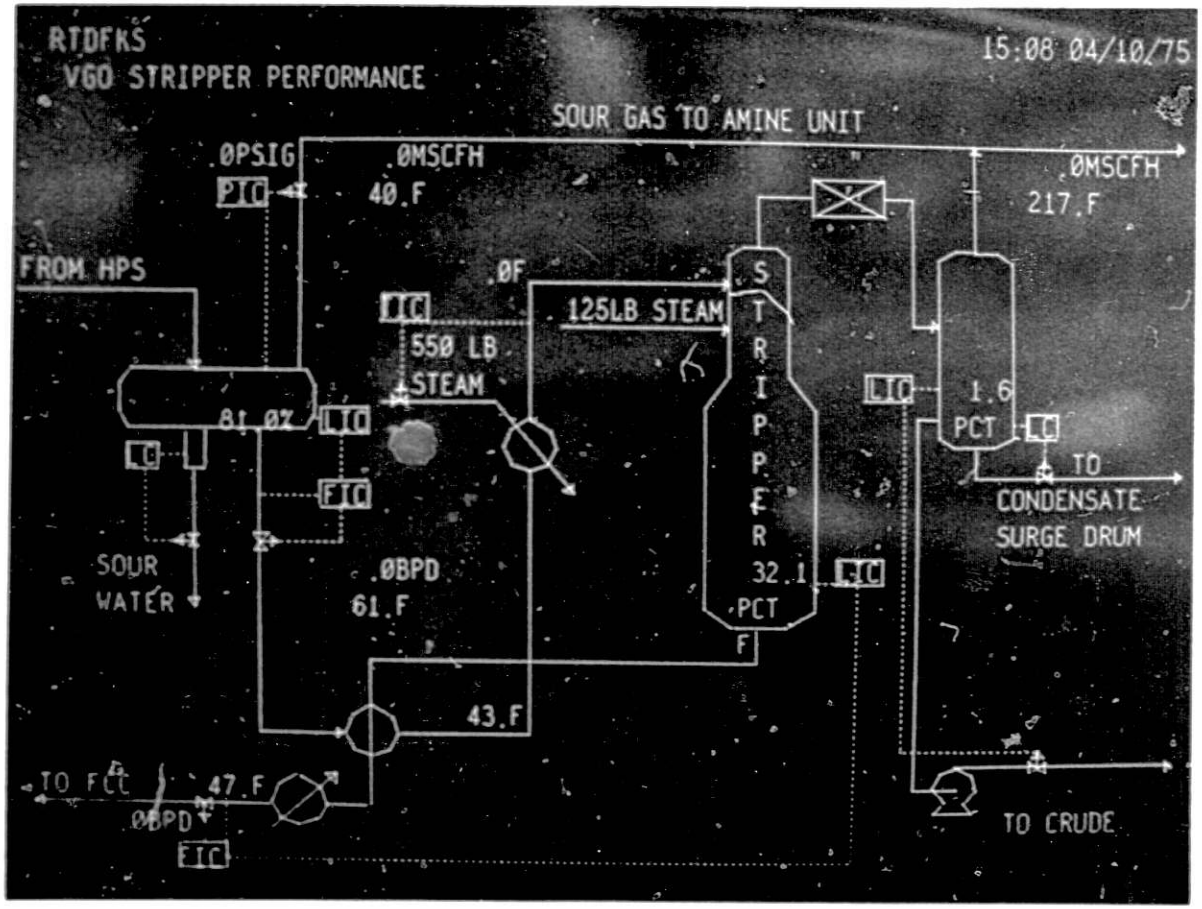

Fig. 7. Typical Computer-based CRT graphic display

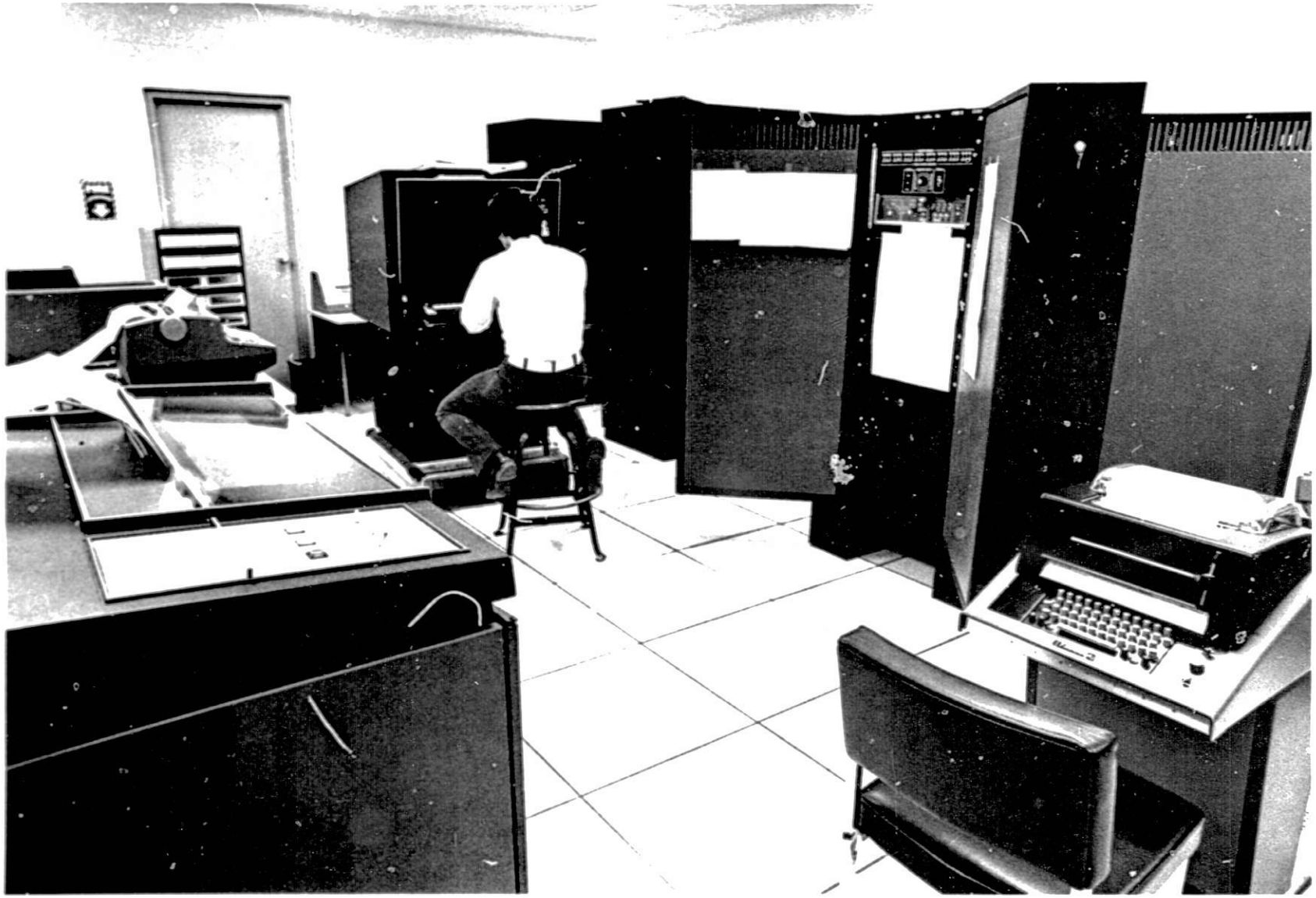

Fig. 8. Computer Room

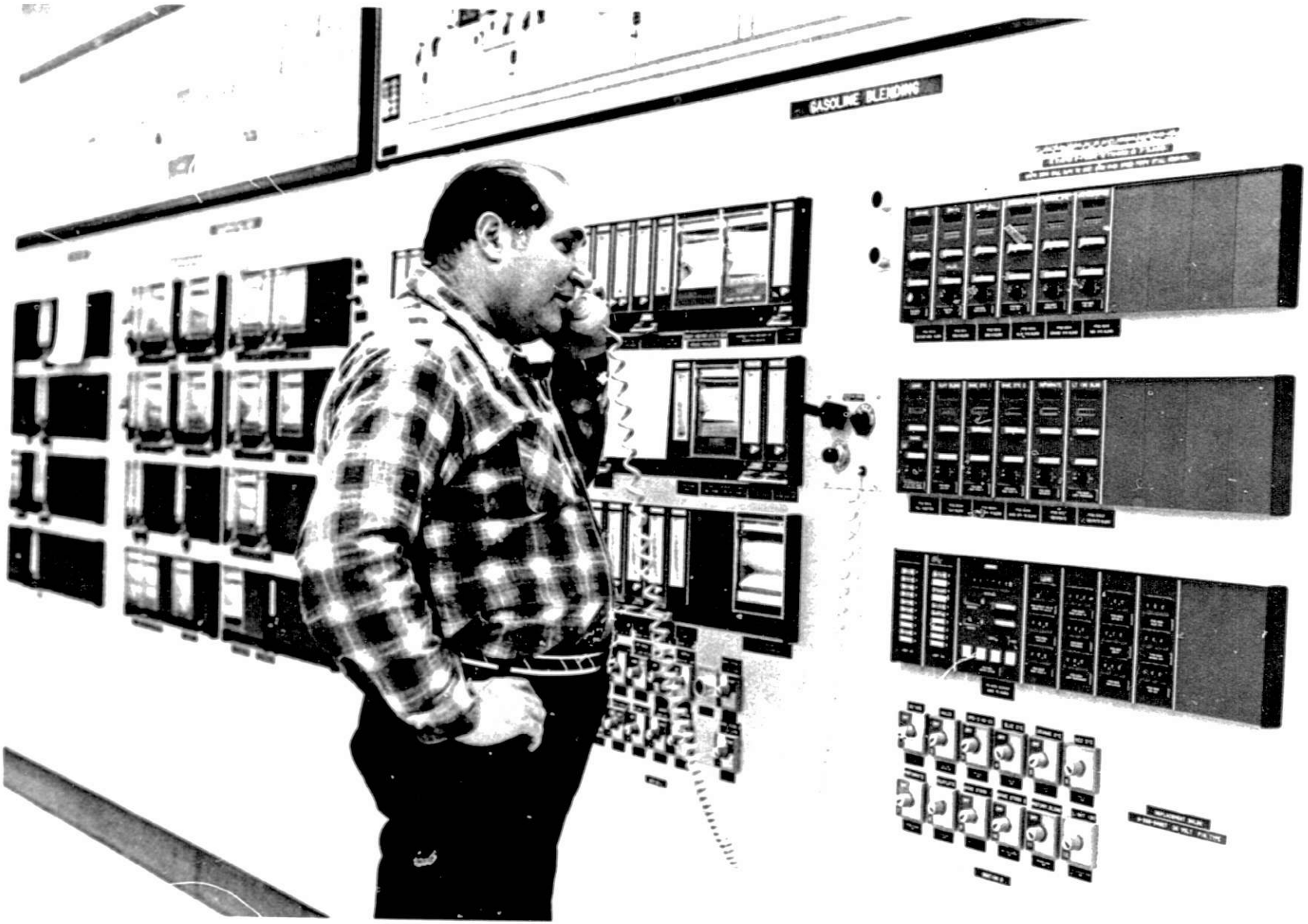

Fig. 9. Blender Control Panel

QUESTIONS AND ANSWERS

K. L. Hopkins

The Standard Oil Company (Ohio)

J. M. Miles, Phillips Petroleum Company

Q. You mentioned that the orifice meters would be the mainly used in the future. Have you tried the Vcrtex shedding meters in your operation?

A. We have not tried the vortex shedding meters. We are aware of it, but we just have not found an application.

B. G. Liptak, Liptak Assoc.

Q. Do you find both the conventional and the CRT displays being used? Are both needed?

A. We find they both are being used, and I think both were needed. I think that we could have eliminated the graphic annunciator and gone to conventional annunciators, but that decision was made before it was decided to develop the graphics on the CRT's. So in the case of the boilers being brought over now into the control room, we will not expand the graphic annunciator, but only go with the graphic CRT.

The computer had all of the data, essentially all of the hundreds of inputs. But it was only intended to have closed loop control on 15% of the control loops. In this system, the percentage that we feel where advanced control techniques are needed. So to do setpoint changes and that sort of thing on the other conventional loops, the conventional panel instrument were used for that.

Q. Was your multiplexing data highway based on microprocessor interfacing?

A. I'm not sure I know the answer to that. Maybe I can give you some information, and you can figure it out. The temperature multiplexing system is an EMC system and the digital gasoline blender multiplexing system was IC Engineering. We did use some redundancy there for reliability such as coax cable transmission system.

Q. Did you implement advanced control such as multivariable or feed forward?

A. The answer here, is basically yes. We did not implement advanced control until after startup. We provided what we though were going to be the controllers with the remote set computer stations and today, two years later, they have closed the loop on about 30 or so loops. This, if you add up four operators, and 110 to 160 loops each, you'll find that's not 15%, but 15% is somewhere 75-100 loops, so we're at 30% or so, to date. There is a task group in the plant that's continuing to move

from one section of the plant to the other, closing loops on advanced applications.

G. N. Reddy, Argonne National Laboratory

Q. How were the magnitudes in variations of various physical and chemical properties of process streams determined for design of the control system mathematical modelling? How are various instruments calibrated?

A. As far as I know we are not using an actual model of the processes for optimization and that sort of thing. There is some modeling done off-line for various case studies. There are laboratory type data and on-stream analyses inputed continuously into the computer base system. That is utilized in some of our calculations of tower loadings, for example, to develop some of the control algorithms. As far as calibration is concerned, nothing special here, the chromatographs, have the computerized normalization of the peaks and so it's sort of self-calibrating that way. But otherwise, we have maintenance people who do the calibrations.

T. P. Mulcahey, Argonne National Laboratory

Q. Any remote manual control stations?

A. No, is the answer there. We do have a few local control loops in the field and there are a few HIC stations on the panel board, but basically all the control is in that control center. The only way the outside operator can take over control of the unit is to go on a bypass, and that is very seldom done.

Q. Any backup in case of loss of computers?

A. The plant can run 100% without the computer, so the analog instrumentation is complete.

Q. How long do you keep data? What form? Mag Tape, printout, etc?

A. Some typed data is kept. I think inside the computer system, generally there is a 24 hour data base.

Q. Any control system scheduled maintenance shutdown?

A. No, refineries operate, generally, for two years, sometimes three years between shutdowns and so we try to design the systems that will be reliable enough to run for that period of time.

Q. Is full remote startup and shutdown capability included through central control room?

A. Basically, yes, the plants are started up and shut down from the control center, but there are people in the field starting and stopping pumps,and opening and closing valves.

Q. What educational level of future operators?

A. That's a good question. I would like to see this improve but I think it's not necessary unless you're going to let them get more active in participating in some of the decision making. How to optimize the operation and so forth. When the plant is running smoothly the operators still sit around without too much to do. So during that period of time if they do have the ability to participate with supervision and management teams, then they could make use of that time. They are talented people, and you're never going to completely include all of the mental processing that the human being does in a computer system.

W. A. Sandstrom, Institute of Gas Technology

Q. Do you chart record, for trends, those pressures and temperatures not on automatic control?

A. Yes. This is done through those selector recorders, trend recorders. There is a program on the computer that was developed for doing some graphical type trending.

E. E. Geraci, Leed and Northrup Company

Q. What percentage of the loops required intrinsic safety?

A. In our system we did not use intrinsic safety on anything. It was all designed and implemented as an explosion proof installation.

Q. Will the trend to intrinsic safety increase?

A. Yes, I think so. It can be more economical.

C. R. Fleming, The Foxboro Company

Q. In an energy intensive process such as a refinery it is interesting to see you have brought boiler controls into the control center. Can you elaborate on how this may have contributed to reducing the energy cost per unit process output?

A. I think the answer to this may lie in the area of energy management. By having all the operations and all of the information in one location you can do a better job of making decisions on conserving energy and distributing your load and knowing just where you're using your energy.

J. A. Depadro, Argonne National Laboratory

Q. What is the number of total points mointored or controlled by computer?

A. The number of points monitored by the computer is two or three thousand. Controlled by the computer, I think we answered that, right now I think it is around 30 loops but we can go quite a bit beyond that.

Q. What is real time update on points? by scan or by change?

A. I think most of the points are updated on the order of magnitude of say one minute.

Q. Are multiplexers dual coaxial?

A. Yes, the IC system was dual coaxial.

E. S. Giordano, Badger Plants Incorporated

Q. Could you elaborate on leak detection instrumentation that might be applicable to coal gasification operations (e.g., CO, H_2, etc., leak detection)?

A. Let me skip that one for now and I'll think about it.

J. Modla, Buell Envirotech

Q. Are you using minicomputers; if so what kind?

A. In this installation, the only minicomputer was a PDP8, which was part of that package gasoline octane system.

Q. What type of micro processors are you using?

A. No micro processors at this time.

Q. Do you have problems with Universal Asynchronous Receiver Transmitters?

A. I don't know. I can't answer that.

Q. What other problems do you have with a computerized set up, ie. equipment breakdown?

A. If you're talking about the breakdown of the computer itself, I'm not directly involved in the computer installation itself, so I really don't know. But after about two years of operation, typically they've had maybe two or three outages. Other than that, any outages have been pretty much planned. So it's been a very reliable system, and it's been in operation now for almost two and one-half years.

Q. What is the cost of a system such as you described?

A. Everything you saw in that control center, including the analog instruments and the multiplexing systems is on the order of a few million dollars. And we think the savings per year are a few million dollars on the systems that we have implemented, including the consolidation and the computer applications.

J. J. Holtgrefe, Badger Plants Incorporated

Q. Programmable controller, to what extent is this used and service.

A. The only programmable controller in this installation, was a square D Norpack type system that was used on reformer regeneration. This

was a (UOP) continuous regenerated reformer. We have at other locations used a true memory type programmable controller on batch reactors. We are going to use programmable controllers extensively on the proposed pipe line at the pump stations for the logic systems. This is the proposed west coast midcontinent pipe line for bringing the Alaskan crude from the west coast into Texas where it can be distributed throughout the midwest.

Q. Solid state, hardwired or part of computer?

A. We've used all types.

A. Let me take a stab at this leak detection question, if we have time. I'm not sure what you mean by leak detection. One form of leak detection is the type we speak of in a pipeline installation, trying to monitor the loss of material, and there are two or three approaches. One is looking at the pressure profile, and seeing how that changes with time. Another is to use a flow-in, flow-out type of dynamic system, and in our pipeline applications, we do both, so technology does exist to do this type of leak detection or line integrity approach.

LUNCHEON

Master of Ceremonies

E. G. Pewitt, Associate Laboratory Director for
Energy and Environment
Argonne National Laboratory
Argonne, Illinois

ENVIRONMENTAL MONITORING IN COAL CONVERSION

M. J. Massey
Department of Chemical Engineering
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Luncheon presentation at the 1977 Symposium on Instrumentation and Control for Fossil Demonstration Plants, July 13-15, 1977, Chicago, Illinois.

ENVIRONMENTAL MONITORING IN COAL CONVERSION

M. Massey, Carnegie-Mellon University
July 14, 1977

Let me begin by apologizing for Lowell Miller's absence. Lowell was unavoidably called out of town and asked that I stand in for him today.

I would like to accomplish two things with you today. First, I would like to broadly outline the program that is currently underway for environmental assessment in the high BTU gas pilot plant program. And I'd like to discuss one segment of that program, one that I trust will be of greatest interest to you, namely the characteristics of the environmental sampling effort that is going on in the pilot plant program.

So let me begin with a broad overview of program structure, objectives, tasks, and timing. Structurally there are two groups of environmental contractors associated with the program. Three contractors are essentially independent industrial contractors: Radian Corporation is working at the CO_2-Acceptor pilot plant in Rapid City, South Dakota; The Institute of Gas Technology (IGT) is working at the Hygas steam/oxygen and steam/iron pilot plant in Chicago, Illinois; Phillips Petroleum is conducting the work at the Bi-Gas pilot plant in Homer City, Pennsylvania. Two contractors are associated with the government-owned and run pilot plants: the Grand-Forks Energy Research Center, operating out of Grand

Forks, North Dakota, on the slagging fixed bed gasifier, and the Pittsburgh Energy Research Center, operating the Synthane pilot plant in Bruceton, Pennsylvania. Finally there is an oversight contractor, Carnegie-Mellon University (C-MU), who has been charged with the responsibility of coordinating and evaluating the activities of the individual contractors at each of the five pilot plants. C-MU's coordination/evaluation function varies with each of the plants. The most direct line of responsibility in the past year has been at the Hygas pilot plant in Chicago and the CO_2-Acceptor pilot plant in Rapid City. Increased attention is being devoted to the Bi-Gas, Synthane, and slagging fixed bed gasification pilot plants as they become fully operational.

The ERDA pilot plant environmental assessment program has three basic objectives. The first is to emphasize the determination of scalable effluent production characteristics of the various pilot plants, as contrasted with emissions which would be outfalls from a commercial-scale plant. As many of you are undoubtedly aware, pilot plant configurations rarely reflect the eventual configurations of larger scale commercial facilities so the bulk of the effluent data generation effort has been focused on those elements of the process which are most scalable. Since the pilot plants are in general, not equipped with complete or scalable effluent treatment systems, emphasis has also been placed on plant effluent production rather than emission.

The second program objective is to generate and close material balances on selected constituents. The primary balances of interest are sulfur, nitrogen and trace metals. A third somewhat less important objective is to characterize plant environmental impacts at the pilot

plant-scale. Assessment of pilot plant environmental impacts is of distinctly secondary interest due to the generally non-representative nature of pilot plant effluent treatment systems.

For purposes of discussion here, program activities can be summarized in terms of five basic tasks. Task 1 involves identification and prioritization of the effluent parameters which are to be monitored during the course of the program. In the absence of established effluent standards and guidelines, significant effort has been devoted to the screening of potentially significant waste parameters which might influence either the treatability or the discharge/reuse potential of individual plant effluent streams. Parameters found to be significant in screening activities are retained in subsequent more comprehensive analysis activities. As you might expect, the list of significant parameters varies somewhat from plant to plant.

Task 2 involves development and verification of sampling, preservation, and analytical methods. Considerable variability has been observed in stream compositions with time at various plants, necessitating the careful specification of stream sampling strategy. (I'll have more to say about this shortly). Selected constituents in plant wastewaters have been found to undergo significant degradation unless properly preserved. Due to the complex nature of gasification wastes, many of the conventional wastewater analytical procedures have had to be modified to give reliable results. A manual detailing verified procedures for the analysis of coal gasification wastewaters will be published shortly.

Tasks 3 and 4 involve the pursuit first of screening and then of comprehensive assessment activities. Effluent constituents found to

effluent data which can be correlated with measured gasifier operating characteristics. Where changes in gasifier effluent production or quench system performance are accompanied by prompt changes in condensate composition, some combination of grab and composite sampling is often adequate. The precise weighting of grab and compositing for optimal, cost-effective sampling varies depending upon the intended use of the data, e.g., material balancing (high degree of precision required), versus baseline monitoring (relatively lower precision required). For a complete discussion of the basic philosophy and strategy for grab and composite sampling, I refer you to two recent program publications on the subject.*

Where condensate composition is either invariant due to excessive dampening, or highly variable, and where detailed correlation with gasifier operating characteristics is desired, modified sampling procedures are required. The best measure of true gasifier effluent production characteristics is obtained by sampling raw gasifier product gases prior to quenching. However, such sampling is typically complicated by a combination of factors, including: (1) high temperatures, (2) high pressures, and (3) multiphase flowing streams of condensing and non-condensing gases, liquids and solids. Significant experimental efforts are underway at four of the pilot plants to develop a successful technique for sampling raw gasifier product gases. Results to date are promising.

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*Koblin, A.H., M.J. Massey and R.W. Dunlap, "Exploratory Analysis of Variations in Aqueous Gasification Effluent Characteristics with Time," Environmental Studies Institute report to ERDA-FE #FE-2496-4, February, 1977.

Koblin, A.H. and M.J. Massey, "Influence of Time Variability on the Design of Sampling Strategies for Coal Gasification Wastewaters," Proceedings of the Second Pacific Chemical Engineering Congress, Denver, Colorado, August 28-31, 1977.

Whether sampling raw product gases or quench condensates, the ultimate goal is to achieve cost-effective automated on-line sampling and analysis. As a part of its overall program effort at Hygas, IGT is developing the mechanical system required to obtain representative automated wastewater samples. Initial field experimentation is scheduled to begin later this summer.

Directly linked to problems of sampling, whether manual or automated, are preservation and analytical problems which stem from the unique characteristics of coal gasification wastes. Substantial experimental work has been conducted at each of the pilot plants to assess the significance of sample degradation and the effectiveness of conventional preservation procedures in retarding it. Results indicate that prompt preservation is required to prevent degradation of some effluent constituents, most notably cyanide, and that certain modifications in traditional procedure are required to maximize effectiveness while at the same time avoiding interferences in subsequent chemical analyses. Any design of an automated sampling and analysis system will have to accommodate the vagaries of coal gasification waste degradation and analysis which have been observed in the pilot plants. Detailed discussions of selected problems can be found in various program contractor reports.

* * * * * * * * * *

In summary, ERDA has assembled a major environmental assessment program effort at its high BTU coal gasification pilot plants the results of which will be of direct value to those interested in the environmental monitoring of larger scale demonstration and commercial scale plants.

REACTOR MEASUREMENTS SESSION

D. P. Mendell, Chairperson
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STATE-OF-THE-ART OF INSTRUMENTATION FOR HIGH TEMPERATURE THERMOMETRY

J. F. Schooley
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STATE-OF-THE-ART OF INSTRUMENTATION FOR HIGH TEMPERATURE THERMOMETRY

James F. Schooley
National Bureau of Standards

1. INTRODUCTION

To the extent that the production of synthetic fuel from coal has been studied on a small scale for many years, some of the instrumentation problems in temperature measurement and control are well-known. The onset of the current energy crisis, however, has brought forth much more intensive and varied approaches to coal conversion. These new approaches have presented new measurement problems, particularly in temperature.

The study of the present state of instrumentation in coal conversion which was accomplished by the Argonne National Laboratory team under the leadership of N. M. O'Fallon[1] has gone a long way toward elucidating the problem areas in thermometry. Among these are the limited high-temperature performance (both the ultimate temperature limit and the rate of failure or of loss of calibration) of thermocouples which are presently in common use, the poor response time of thermowell-protected temperature sensors, and measurement errors associated with radiation pyrometry. Some of these problems will be discussed in other talks, particularly that of N. Pitcher.

Recent innovations in high-temperature thermometry can be expected to improve both the quality and the efficiency of the coal conversion process. New, more stable thermocouple systems have been developed which are capable of providing longer-term reliability at higher temperatures than the Type K systems now in common use. Alternatives to thermocouple sensors have been developed and tested in other high-temperature environments. Among these, the acoustical, or velocity-of-sound, thermometer, the Johnson noise voltage thermometer, and the radiation pyrometer deserve mention.

In the following sections, I will present a brief discussion on the use of specially-prepared tungsten-rhenium alloy thermocouples and platinum-rhodium alloy thermocouples for extended-term temperature measurements above 1200 °C, and on the use of a new nickel-based (Nicrosil-Nisil) thermocouple for lower-temperature measurements. I will also note the recent progress in sound-velocity thermometry and in Johnson noise thermometry. Finally, I will present some general remarks on radiation pyrometry as a preface to the discussion by R. F. Leftwich.

2. HIGH-TEMPERATURE THERMOMETRY MEASUREMENTS IN THERMOWELLS

Most process temperature measurements involve the use of sheathed, insulated thermocouples in thermowells, and for the most part Type J or Type K thermocouples are favored. The upper temperature limits for which these thermocouples are recommended even in as heavy a gauge as #8 are 760 °C and 1260 °C, respectively. ASTM Publication STP 470A[2] summarizes these and other recommendations, including general comments on thermocouple behavior in various chemical environments.

I have three general comments to make in regard to high temperature thermometry using thermowells:

- First, in such measurements the problem of thermowell survival is almost a separate question from that of the survival and accuracy of the temperature sensor which is to be used therein;
- Second, the use of a thermowell almost automatically precludes the realization of a quick response (less than a few minutes) to changing temperatures within the process chamber;
- Third, the difficulty and expense involved in fabrication and insulation of the thermowell-sensor system are in general sufficiently large that there is little point in economizing on the material of which the sensor is composed.

Briefly stated, it is my opinion that in thermometry involving the use of thermowells, one should consider installing carefully-constructed, insulated, sheathed thermocouples of such a type as have been demonstrated to yield maximum stability and accuracy for the temperature which is anticipated. I shall give three examples of such thermocouple types.

Nicrosil-Nisil Thermocouples

For the temperature range up to 1200 °C or 1250 °C (2200 °F or 2282 °F), a new nickel-chromium alloy thermocouple has been shown to be substantially superior in long-term stability to the Type K thermocouple. The new alloys, known as Nicrosil and Nisil, were developed over the past decade in a worldwide effort to improve on the performance of the Type K thermocouple. The major role in the development of the Nicrosil-Nisil thermocouple was played by the Australian Materials Defence Laboratory[3]. A systematic evaluation of the emf-temperature values of wire lots of Nicrosil-Nisil prepared by various manufacturers has been completed at the National Bureau of Standards

in cooperation with the Australian MDL. A monograph which discusses this study and which presents tables of the emf over the range of temperature -269 °C to +1300 °C is now in press[4]. A comparison of the emf-temperature relation for Nicrosil-Nisil and Type K thermocouples is shown in Fig. 1. A comparison of the stability of the two types of thermocouples is shown in Fig. 2 at 1200 °C. Despite its somewhat reduced temperature-dependent sensitivity, the Nicrosil-Nisil thermocouple is significantly more stable than the Type K thermocouple. This improvement is primarily owed to optimization of the solid-state diffusion and oxidation stability properties of the newer alloys. Thus, the new thermocouple offers the possibility of long-term (hundreds of hours) service at temperatures exceeding 1200 °C with as little as 5 °C drift from the initial temperature calibration.

Platinum-30% Rhodium versus Platinum-6% Rhodium (Type B) Thermocouples

For the temperature range up to 1700 °C (3100 °F), the well-known Type B thermocouple offers a very reasonable solution to the problem of long-term stability in a thermowell-sheathed thermocouple application. Often ignored because of the expense of its noble-metal composition and reduced sensitivity compared to Type K, the Type B thermocouple can be the most economical installation in view of its ability to maintain its initial calibration.

Glawe and Szaniszlo[5] examined 3 Type B thermocouples in argon gas at 1330 °C in a long-term drift test. The drifts after 10,000 hours of exposure ranged from -7.2 to -18.1 °C, illustrating the high degree of reliability which can be achieved with noble-metal thermocouples.

Fig. 3 shows the emf-temperature relations of the four letter-designated base-metal thermocouples and of the three letter-designated noble-metal thermocouples.

Tungsten-3% Rhenium versus Tungsten-25% Rhenimum Thermocouples

Tungsten-rhenium alloy thermocouples are useful thermometers for measuring temperatures as high as 2760 °C (5000 °F). Reference ? describes three commercially-available thermocouples of this type. Fig. 4 shows their emf-temperature relation compared to that of Type S.

Recently, the NBS completed studies which demonstrated the value of careful selection of thermocouple wire, insulation, and sheathing and of carefully assembling these starting materials into a system as free of impurities as possible[6]. The data of Fig. 5 speak for themselves. At 1800 °C

(3272 °F), the NBS—prepared thermocouples showed a decrease of some 1 °C per 1000 hours. In contrast, commercially-prepared thermocouples of the same type showed an initial decrease of some 50 °C per 1000 hours at 1800 °C[7].

It should perhaps be noted that once a thermocouple thermometer has been fabricated in the configuration of an insulated, sheathed sensor (especially one which is hermetically sealed in the presence of an inert gas), it can be calibrated with considerable confidence in a dummy thermowell which is maintained in a test oven.

3. FAST-RESPONSE THERMOMETRY

Just as the thermocouple theoretically has the capability of responding quickly to a change in its high-temperature environment, other thermometers offer the same possibility. I shall discuss three such thermometers in this section—the acoustical thermometer, the Johnson noise thermometer, and the radiation pyrometer.

Scarcely anyone attending this Conference needs to be told that the thermocouple's potential (perhaps a slight pun is intended) for rapid, accurate thermometry cannot be realized under the extreme conditions of coal conversion processes. The susceptibility of thermocouples to oxidation or reduction, to impurity contamination, and to variations in effective immersion depth consigns them, in the context of this discussion, to the protection of relatively cumbersome insulants, sheaths, and thermowells. In such an installation, they may well provide an invaluable baseline of temperature accuracy, but only a sluggish response to changing temperatures.

The other thermometers which I have mentioned must also submit to scrutiny on the same grounds—can they deliver fast, accurate temperature information over a long period of immersion in the process environment?

Acoustical Thermometers

The acoustical, or velocity-of-sound, thermometer can be used in either a pulse or a resonant mode to measure temperature with solid, liquid, or gaseous sensors. In one realization of this concept, acoustic resonances in a gas are detected as the piston in a cylinder is moved through a measured distance. The most accurate measurements of this type (5-10 millikelvins uncertainty) have been made at low temperatures (30 K [-243 °C] and below) utilizing the relation between the thermodynamic temperature and the velocity of sound as follows:[8][9]

$$V^2 \ (P \approx 0) = \frac{C_p}{C_v} \frac{R}{M} T.$$

V = velocity of sound (of a perfect gas, i.e., $P \approx 0$).

C_p, C_v = heat capacity at constant pressure or volume.

R = gas constant.

M = gas molecular weight.

T = thermodynamic temperature.

The same basic relationship governing the velocity of sound in gases has been used at high temperatures as well, both in automobile combustion thermometry[10] and in gas turbine thermometry[11]. The thermometer systems in both cases sampled the actual combustion mixtures, but no data were given regarding long-term performance.

A group at the University of Aston at Birmingham, England, has been studying the resonant detection of ultrasound velocity in solid probes[12]. Both refractory metals and ceramics have been studied as probe materials, and an unsheathed sapphire probe has been found to be particularly advantageous, allowing a flame temperature of 1900 °C to be measured with an imprecision of some ±2 °C. In this application, the oscillator frequency is maintained at the probe resonance value by sensing the change in phase of the reflected echoes from the probe.

Ultrasonic pulse techniques have been used for several years to measure high temperatures in gas turbines, nuclear reactors, and other difficult environments. In an in-pile study at Karlsruhe, Tasman and his co-workers used thoriated tungsten sensors sheathed with tungsten-25% rhenium to determine reactor fuel-pin temperatures[13]. A modified co mmercial pulse-echo timing unit was employed, see Fig. 6, and a sensitivity of ±15 °C at 1800 °C was observed. However, the intense nuclear flux soon degraded the performance, probably as a result of transmutation and lattice degeneration in the sensor.

A study similar to Tasman's was conducted at the Oak Ridge National Laboratory by Shepard and others[14]. They used a rhenium sensor sheathed in a W-Re alloy tube. Fig. 7 shows the very large shifts in calibration which they found in the process of some 2500 hours of in-pile testing.

O'Fallon, et al., in Ref. 1 present an extended discussion of the pulse technique as applied to temperature measurement in coal conversion. A fair

summary of the major points in this discussion might be the following:

- A single-ended sensor, which need not be conducting, may be used in this technique. In some cases one can consider employing an unshielded, fast-responding, highly-stable sensor made of a refractory metal or of a ceramic such as sappnire. Elsewhere, the use of thermowells may be necessary.
- The pulse transducer must be compatible in frequency and placement with the size, shape, and composition of the sensor.
- The possibility exists of measuring temperature profiles by the introduction of several acoustic impedance changes into the sensor.

The usefulness of acoustical thermometry for instrumentation in coal conversion processes seems to me to hinge on a demonstration of its extended-term performance at high temperatures. The disastrous deviations from the initial calibration reported by the Oak Ridge National Laboratory group for the sheathed rhenium ultrasonic thermometer could well have resulted simply from the intense nuclear flux in the HRB-5 experiment. On the other hand, the group at the University of Aston have only very short-term data on their unshielded sapphire probe. It seems likely that both surface damage to the sensor and any substantial change in its internal lattice characteristics will result in degradation of the sensing signal and also in a deviation from the original calibration.

Johnson Noise Thermometers

It is an unfortunate coincidence that brings acoustic thermometry and Johnson noise thermometry to the same conference; the unwary confuse the two, because the word "noise" often carries an acoustic connotation. I carefully note here, therefore, that "Johnson noise thermometry" refers to the process of inferring the temperature of an electrical resistor from a study of its random voltage spectrum. This voltage, arising from the thermal excitation of the conduction electrons in the resistor, was studied experimentally by Johnson[15]. A theoretical discussion was presented at the same time by Nyquist[16]. The relation between the "Johnson noise voltage" and temperature can be approximated as

$\overline{V^2} \approx 4\ kT\ Rdf$, where

$\overline{V^2}$ is the mean square voltage of the fluctuations in a

frequency band between f and f + df

R is the resistance of the resistor

k is the Boltzmann constant

T is the kelvin temperature

df is the instrumental band width.

Realizations of Johnson noise measurements of temperature are found at NBS in Washington, where Soulen uses superconductivity voltage detectors to measure absolute temperatures in the range 0.01 K to 0.5 K with an estimated accuracy of 1 or 2 millikelvins[17]; also at the Australian National Measurements Laboratory, where C. P. Pickup uses a switching-type detector to compare the ratio of noise voltages from a resistor at an unknown temperature to that held at a fixed, known temperature[18].

An experimental study of absolute thermometry up to the melting point of gold using the same concept of noise voltage ratios between two resistances, one of which is held at a fixed temperature, is underway at the Istituto di Metrologia "G. Colonetti" (the Italian National Standards Laboratory at Torino). Using commercial metal film resistors for the reference temperature, and silica-insulated platinum resistors for the high temperature measurements, Crovini and Actis find an estimated uncertainty in absolute temperature of ±0.2 °C to ±0.35 °C from 630 °C to 962 °C[19].

Encouraged by a study of Borkowski and Blalock on Johnson noise thermometry as a high temperature technique[20], the Oak Ridge National Laboratory thermometry group under Shepard has developed a Johnson noise thermometer for use in nuclear reactors. The Oak Ridge group again employed the technique of noise voltage ratios (essentially to evaluate the amplifier gain constant) with the important refinement of measuring both the open circuit noise voltage and the short circuit noise current. A block diagram is shown in Fig. 8. This refinement, they found, allowed for changes in the sensor resistance during irradiation by the nuclear flux. They operated a sensor with a rhenium resistor in a Mo-Re alloy sheath; it was irradiated in a high-flux experiment for some 1100 hours at 1250 °C. At the end of the experiment, the unit was found to be within 20 °C of the initial calibration[14].

Because of the danger of extraneous noise pickup from electromagnetic interference, the use of unshielded Johnson noise thermometer probes is not

recommended[21]; this factor is certain to increase the sensor's thermal response time. However, the Johnson noise thermometer has proved to be extremely stable even in the nuclear environment. This stability is very largely owed to the alternating measurement of noise voltage and noise current in the Oak Ridge system, so that changes in the sensor resistance, from whatever cause, tend not to influence the overall temperature determination. This feature makes the noise thermometer a promising candidate for coal conversion thermometry.

Radiation Pyrometry

Radiation pyrometers are capable of providing fast response coupled with very reasonable accuracy at high temperatures. In order to realize this capability, however, each installation must be examined in detail.

R. F. Leftwich, in a later talk, will discuss many of the particular problems associated with radiation thermometers, so that I will make only a few general comments on this topic:

- The radiation pyrometer can respond, in times in the range of milliseconds to seconds, to changes in the temperature of the first opaque surface from which it receives radiation.
- Depending upon the instrument's effective wavelength, this surface may be solid, or it may be the envelope of a gas or a liquid.
- The radiation from a relatively cool surface may be substantially augmented by reflected radiation from a nearby hotter surface.
- The use of windows or of fiber optics implies transmission losses which may change with time during exposure to high temperatures and to chemically active environments, although in some applications, this problem can be circumvented by the use of gas purged, windowless installations.
- Infrared imaging systems are available which can give real-time temperature data on the external surfaces of combustion tanks, pipelines and the like. This type of equipment offers the possibility of either periodic or continuous monitoring for hot or cold spots, identifying thin or defective insulation or partially plugged lines.

4. SUMMARY

I have tried to present in this talk a discussion of innovations in the practice of high-temperature thermometry which appear to be relevant to the problems evident in modern coal conversion processes.

It is my opinion that, in steady-state measurements where one can tolerate the relatively slow response times which accompany the use of thermowells, the installation of carefully prepared modern thermocouples such as Nicrosil-Nisil, Type B, and tungsten-rhenium alloys can provide extended-term, accurate service. I wish to emphasize, however, the importance which recent investigators have demonstrated of the selection of well-characterized materials for the thermocouples themselves, for the electrical insulation, and for the sheaths; and the dividends paid in terms of extended thermocouple life for the investment of effort in cleanliness and in care in assembly.

The Johnson noise thermometer, too, has been demonstrated to be an extended-life, highly accurate, high temperature instrument. The extent to which it will satisfy existing needs for fast thermal response, however, is uncertain.

The acoustical thermometer can take many forms, using gaseous, liquid, or solid sensors; the solid sensors may be metals or insulators. Either timed-pulse or resonant-frequency detection methods may be used. The acoustical thermometer is thus a versatile technique. Its usefulness for extended-term, high temperature measurements has yet to be demonstrated, however, and it appears that the sensor must remain free from either internal or external attack by its environment in order to realize that goal.

The use of radiation pyrometry for accurate, extended-term measurements appears to depend upon a rigorous calibration technique. A significant advance may be possible in cases where the "window problem" can be circumvented.

Finally, I think that presently-available thermal imaging techniques can serve the needs for "hot-spot" detection, owing to thin or defective insulation or partially plugged lines, serving both as a safety measure and as a significant energy conservation technique.

In preparing this talk, it has been my pleasure to discuss various aspects of thermometry with my colleagues. I wish particularly to acknowledge the generous technical assistance of Mr. G. W. Burns and the preparation

of slides and figures by Mrs. M. G. Scroger.

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FIGURE CAPTIONS

1. EMF-Temperature Relationship of Some Nickel-Base Alloy Thermocouples; Reference Junctions at 0 °C.

2. Change in Calibration With Heating in Air at 1200 °C of 8 gauge Type K and Nicrosil-Nisil Thermocouples. (Data of N. A. Burley and T. P. Jones (22)).

3. EMF-Temperature Relationships of Standard Letter-Designated Thermocouples, Reference Junctions at 0 °C.

4. EMF-Temperature Relationships of Tungsten-Rhenium Alloy Thermocouples, Reference Junctions at 0 °C.

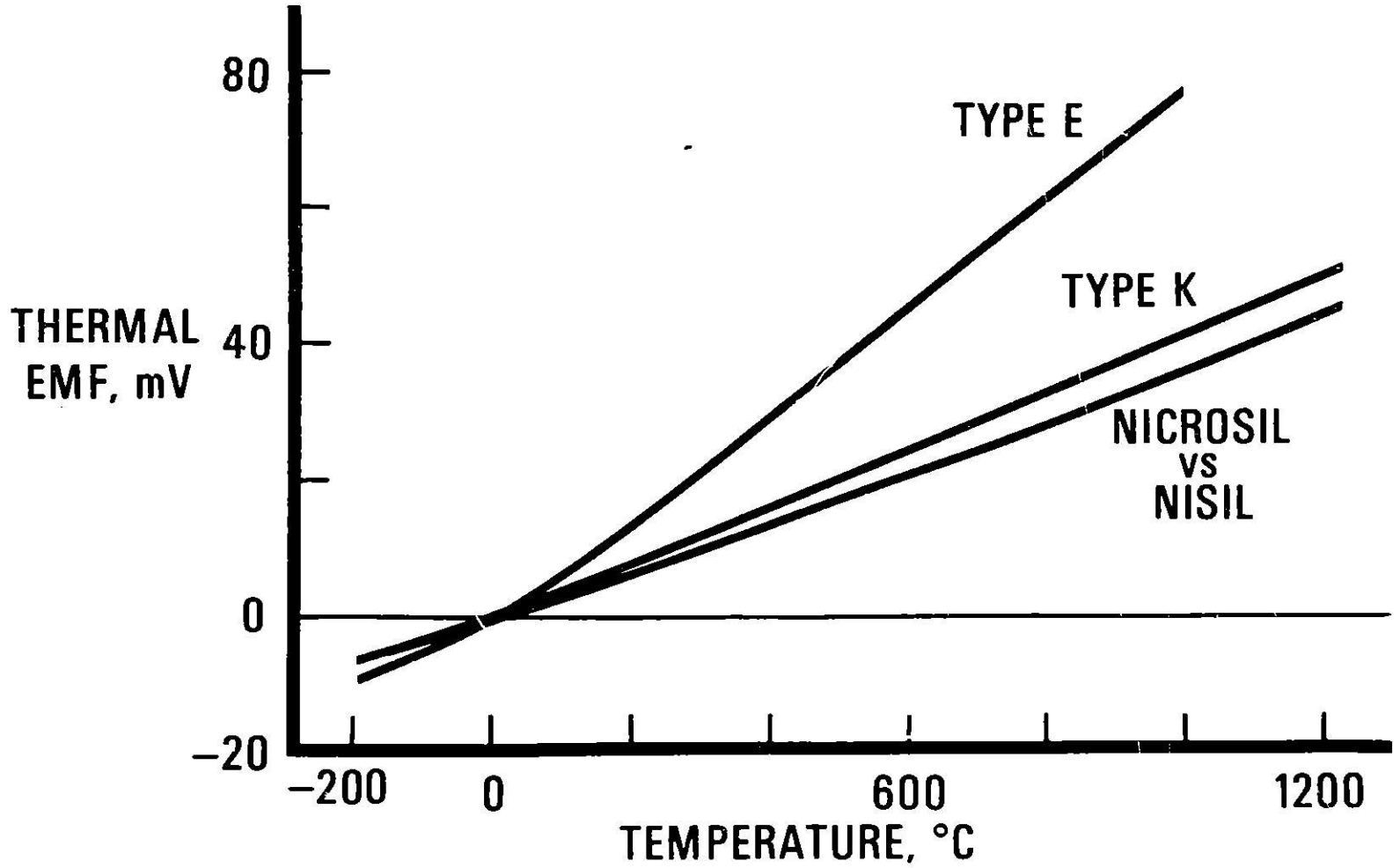
5. Drift in Calibration at 1800 °C of NBS-Built and Commercially-Built 1.6 mm o.d., Ta-Sheathed, BeO-Insulated, W-3% Re/W-25% Re Thermocouples (Data of G. W. Burns and W. S. Hurst (6) and Heckelman and Kozar (7)).

6. Block Diagram of Ultrasonic Thermometer System. (From Shepard, et al., Ref. 14).

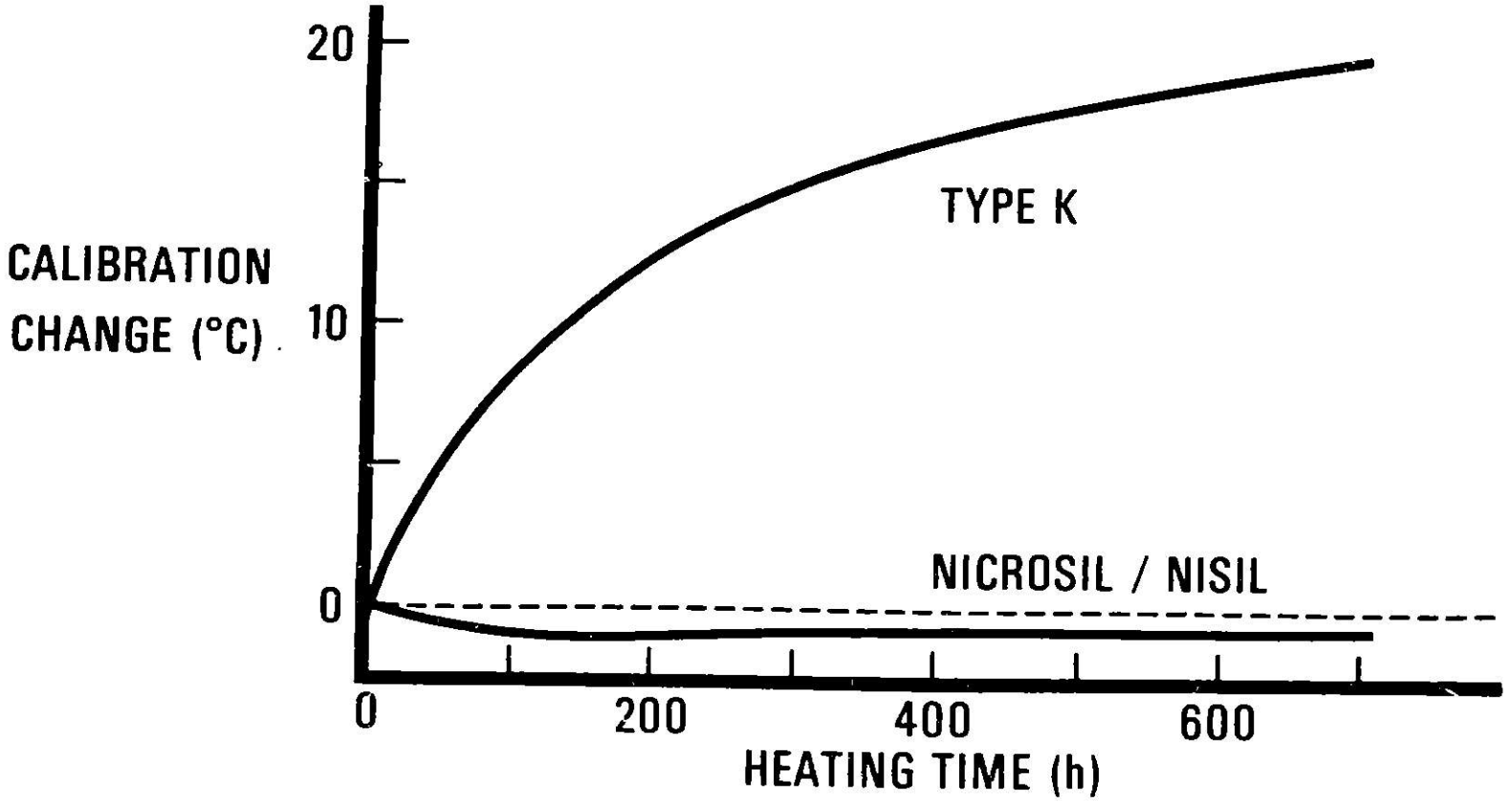
7. Change in Calibration of Ultrasonic Thermometer During Irradiation (From Shepard, et al., Ref. 14).

8. Block Diagram of Johnson Noise Thermometer System (From Shepard, et al., Ref. 14).

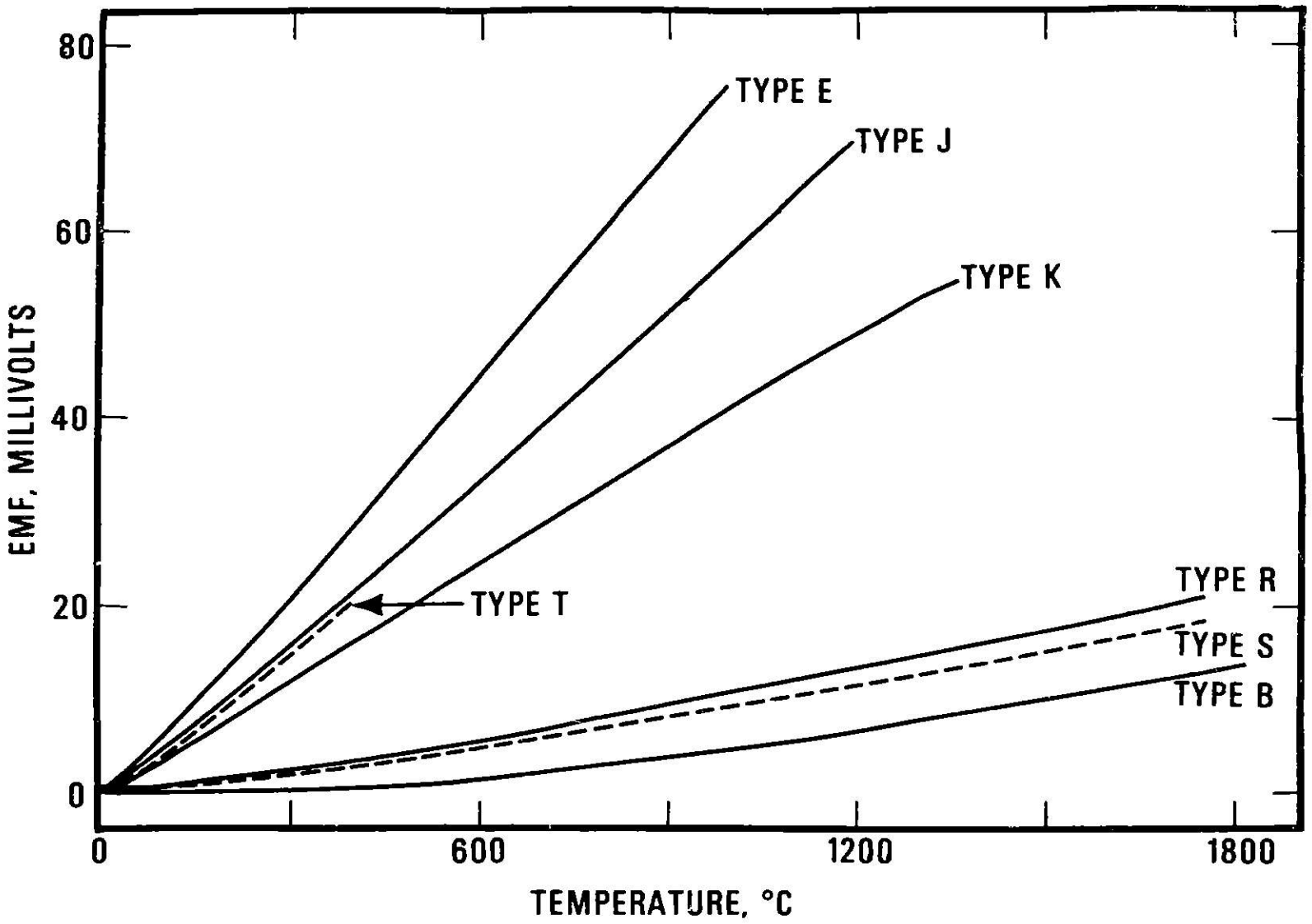
EMF – TEMPERATURE RELATIONSHIP OF NICKEL-BASE ALLOY THERMOCOUPLES



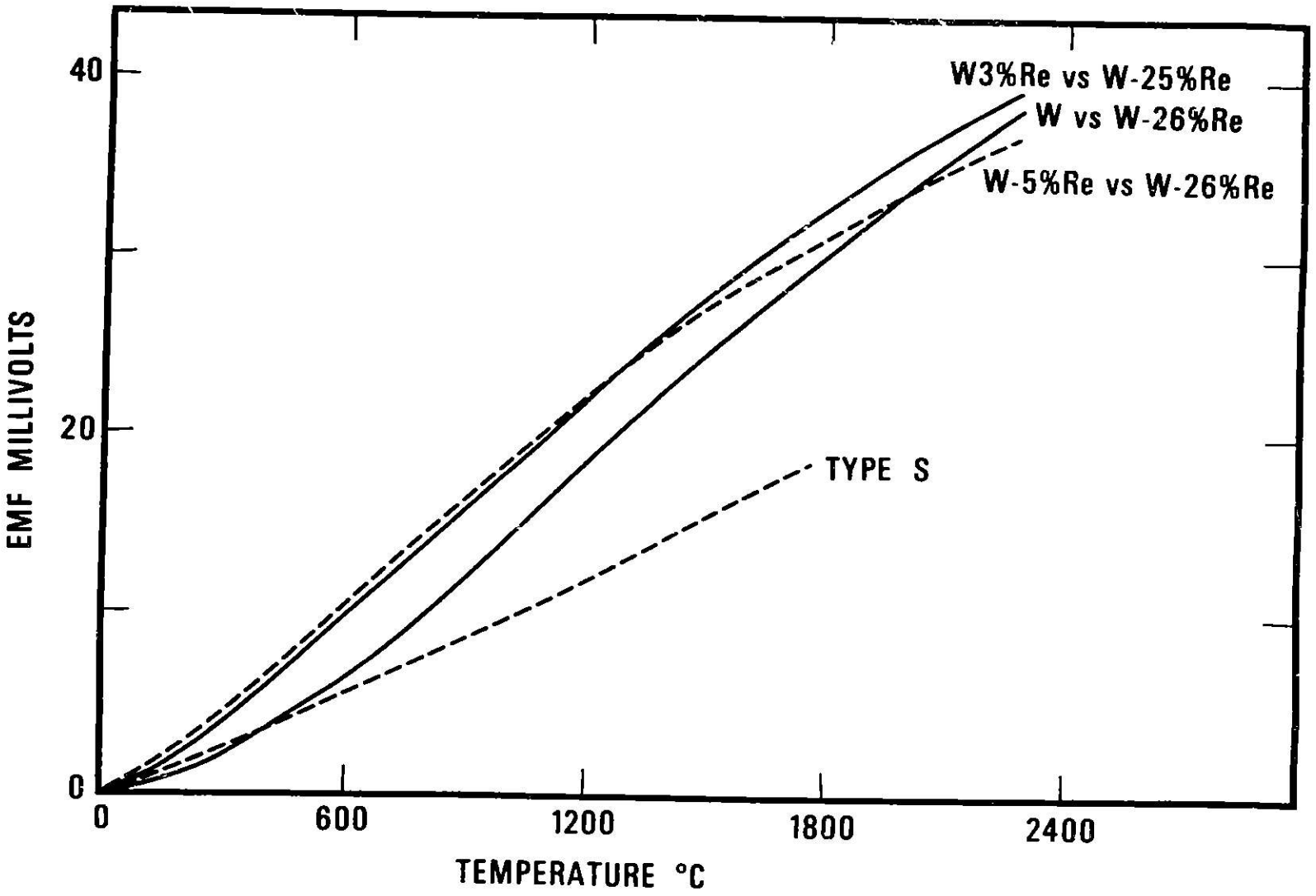
CHANGE IN CALIBRATION OF NICKEL BASE ALLOY THERMOCOUPLES WITH HEATING IN AIR AT 1200°C

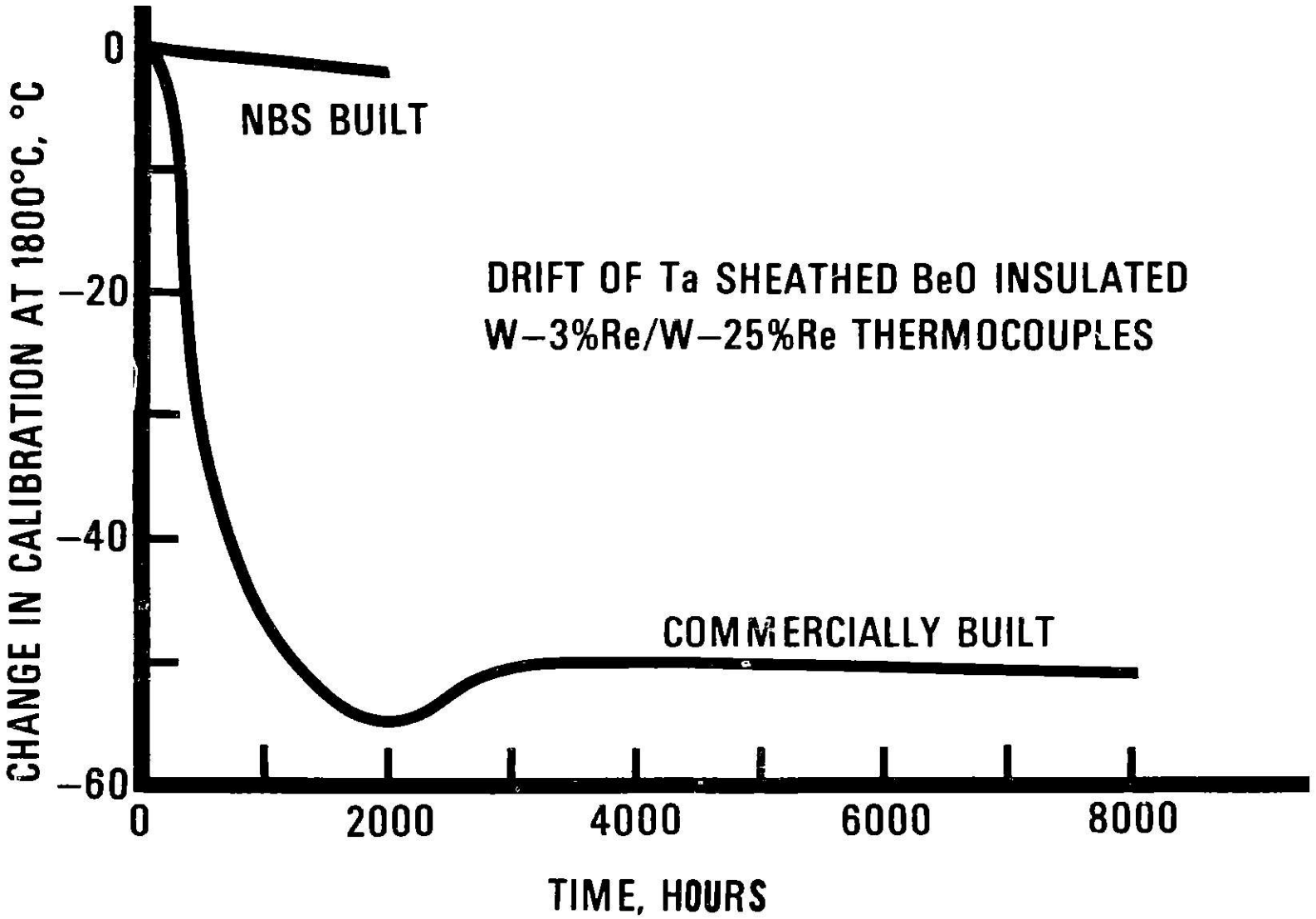


TEMPERATURE – EMF RELATIONSHIP OF LETTER DESIGNATED THERMOCOUPLES

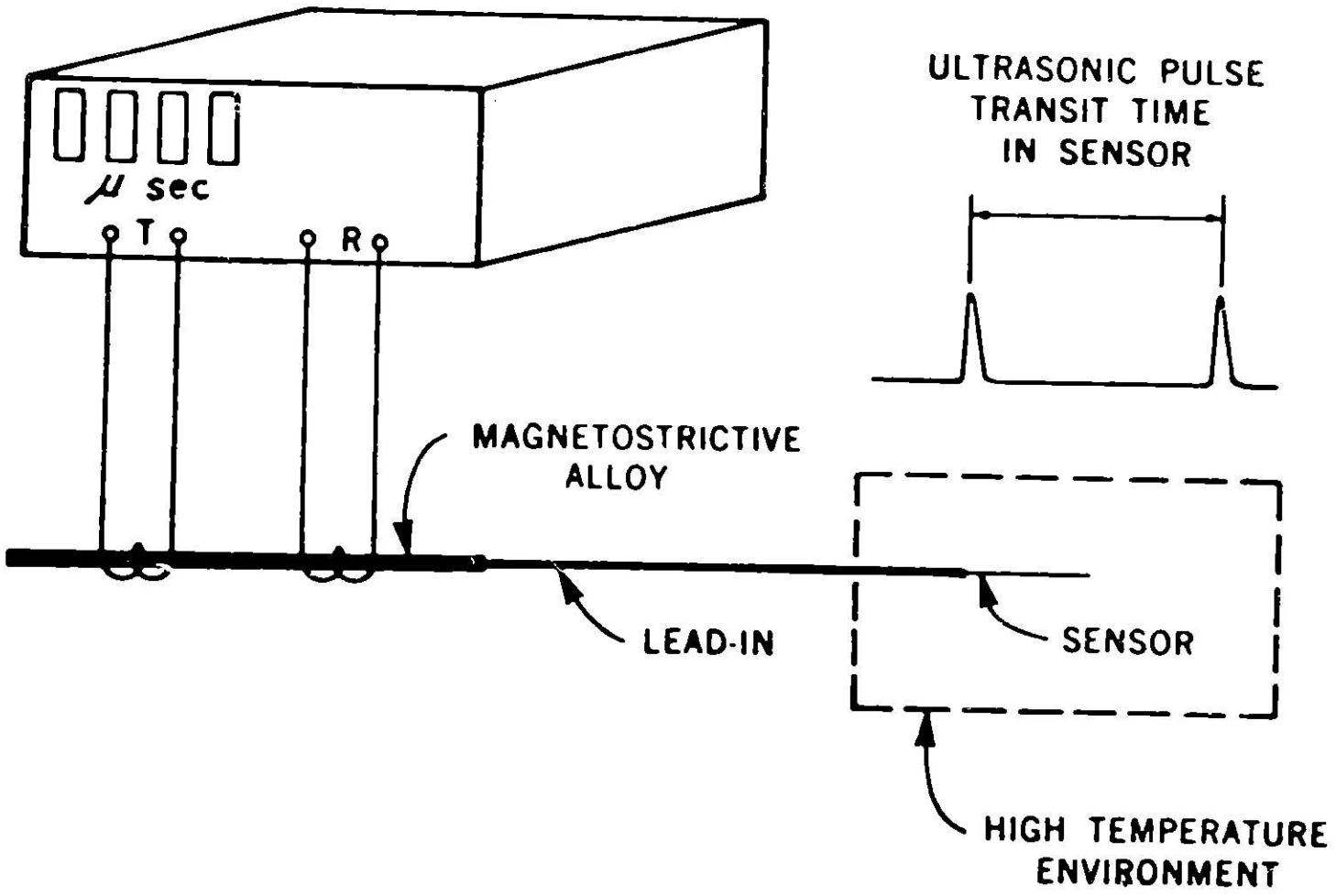


TEMPERATURE – EME RELATIONSHIP OF W-Re ALLOY THERMOCOUPLES

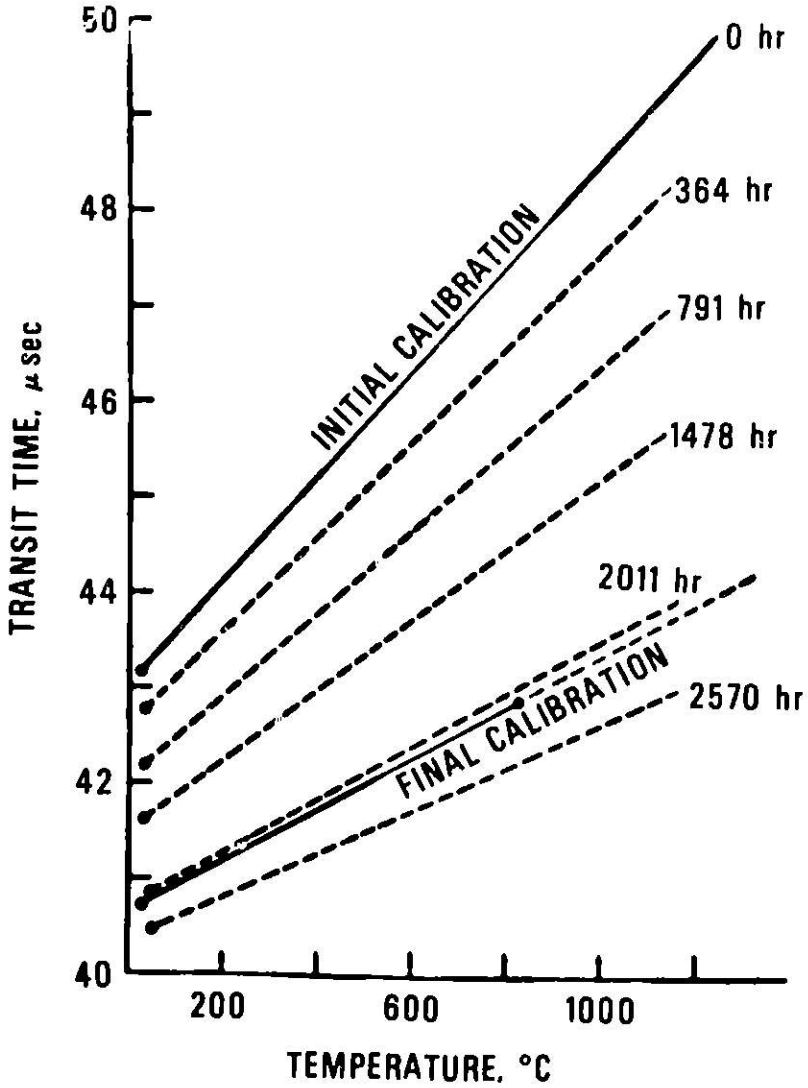


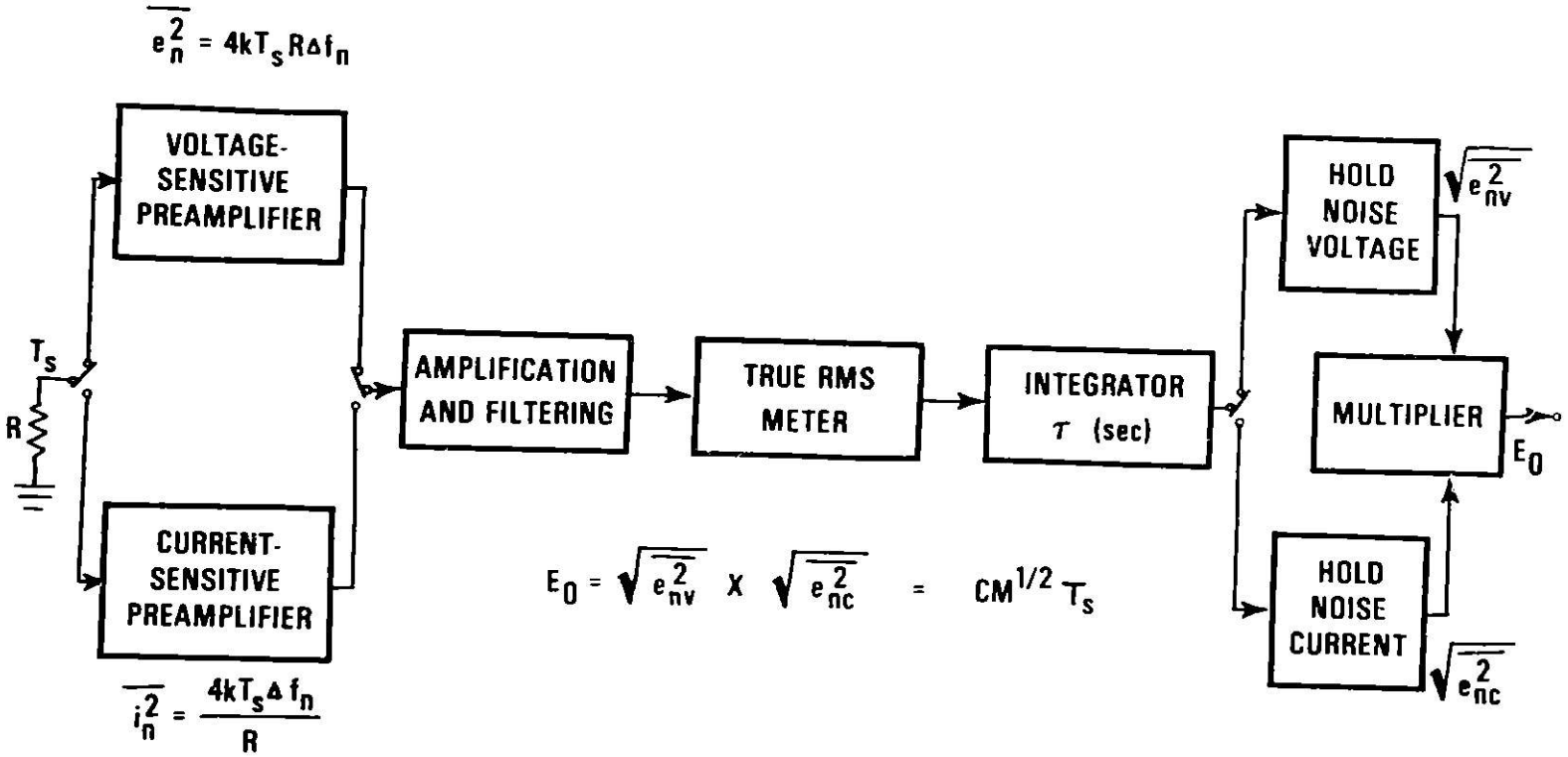

DRIFT OF Ta SHEATHED BeO INSULATED
W–3%Re/W–25%Re THERMOCOUPLES
NBS BUILT
COMMERCIALLY BUILT
CHANGE IN CALIBRATION AT 1800°C, °C
0
–20
–40
–60
0
2000
4000
6000
8000
TIME, HOURS

ULTRASONIC THERMOMETER



IRRADIATED RHENIUM ULTRASONIC THERMOMETER DRIFT HRB-5 EXPERIMENT





A SYSTEM FOR MEASURING THERMAL NOISE POWER

QUESTIONS AND ANSWERS

J. F. Schooley

National Bureau of Standards

R. A. Hanson, Taylor Instruments

Q. Do RTDs have longer lives than thermocouples?

A. The answer to this question is that it certainly depends on the use to which they are subjected. Most of the commercial RDT's, which are commonly made of copper, nickel, or platinum, have upper temperature limits which range between 850 and 1000°C. The major problem that they have is that on temperature cycling they tend to decalibrate, although the magnitude of the decalibration, I would say, is not severe from the point of view of most users. It is an important factor, however, when high accuracy and precision are sought. The RTD is a large sensor and is restricted by its encapsulation or its ceramic or plastic basis to certain temperature ranges. Thermocouple thermometers, when properly insulated and protected, can function reliably for very long times in these temperature ranges, but, of course, their useful lives in unfriendly environments, such as those found in the coal gasification processes, can be greatly shortened.

Q. When would you use RTD's instead of thermocouples?

A. I would use RTD's instead of thermocouples, for example, if I needed a temperature measurement in which I needed an average temperature. I can then use an RTD which covers a spatial range whereas a thermocouple really covers a point range. Also, the effects of temperature gradients along the leads are more severe with thermocouples than they are with resistance thermometers.

W. R. Miller, Stearns-Roger

Q. Do you have any experience or published literature on grain boundary embrittlement, due to temperature cycling in tungsten-tungsten rhenium thermocouples, in the range of 2200°F to 2600°F?

A. I'm going to refer you to my local expert. Mr. George Burns, at NBS, knows a great deal about thermocouples. Burns' group has done a lot of research on the tungsten-rhenium system and they have published reports containing information on the recrystallization behavior and mechanical properties of tungsten-rhenium type thermocouples. I can also refer you to experts from the Oak Ridge National Laboratory temperature group, some of whom are right here.

E. W. Lazor, Babcock and Wilcox Research Center

Q. What value ΔF (bandwidth) are you talking about as typical?

A. I guess I can't give a value for that bandwidth in the Johnson noise thermometer, and I'll have to refer you to the Petten paper of Shepherd, et al.

D. L. Bonk, Babcock and Wilcox Research

Q. What is the present commercial availability of nicrosil-nisil thermocouples? Also when will the NBS, emf tables on N-N thermocouples actually be published.

A. The actual publication of the tables is the easier one to answer. They will be out before the end of this year. They're through editorial review by all authors and they are now in the NBS editorial review process. They will be going to the printer within the next few months. As to the commercial availability, I understand that both the Wilbur B. Driver Company and the Driver-Harris Company are now manufacturing these thermocouples. I might point out that there are several organizations around the country doing independent evaluations of the thermocouple. For example, I believe the Oak Ridge temperature group is conducting stability studies at the present time on very small diameter devices using nicrosil-nisil thermocouple wires. Finally, I suspect the commercial availability of the thermocouples will probably lead that of measuring and control instrumentation by some time. I know of no commercially available instrumentation for use with these thermocouples at this time. However, lots of wire which closely conform with the tables, can now be obtained commercially.

A. P. Van der Klay, Amoco Oil Company

Q. How much lead time do you need for calibration of thermocouples to be used as standards for industry?

A. The turn-around time for the calibration of most thermocouple types is about three weeks. However, if you arrange the arrival time of your thermocouples with our laboratory personnel, this turn-around time can usually be reduced.

E. E. Geraci, Leed and Northrup

Q. Can you compare bulk or thin film RTD's to conventional RTD's or thermocouples with regard to range and stability?

A. They are really rather different sensors. Thin film RTD's may be used to 500°C or so, whereas bulk RTD's may reach 800°C to 1000°C. Thermocouples, as we have noted, are still useful above 2000°C. Stability of the RTD's range up to ±0.5°C, which is comparable with or better than industrial thermocouples.

MEASUREMENT OF PRESSURE, FLUIDIZED BED LEVEL, AND DENSITY IN THE SYNTHANE PILOT PLANT COAL GASIFIER

D. M. Bailey, Assistant Plant Manager
Synthane Pilot Plant
The Lummus Company
Bloomfield, New Jersey

ABSTRACT

MEASUREMENT OF PRESSURE, FLUIDIZED BED LEVEL, AND DENSITY IN THE SYNTHANE PILOT PLANT COAL GASIFIER

Fluid bed densities and levels are usually obtained from measurement of differential pressures between taps with a known vertical separation. Historically, this measurement has been difficult in high pressure coal gasification processes primarily due to plugging of the pressure taps and process instrument tubing. Likewise, the achievement of accurate and reliable pressure and differential pressure recordings is affected by similar circumstances.

These typical problems were experienced at the SYNTHANE Pilot Plant at Bruceton which is operated for the U. S. Energy Research and Development Administration by the C. E. Lummus Company. Major changes were required in instrument location and selection, piping configuration, and methods of purging. Consistent and accurate data is now obtained.

BACKGROUND

The gasifier at the ERDA SYNTHANE Pilot Plant, as depicted in Figure No. 1, is a 101 foot tall pressure vessel designed to operate to 1000 psi. The vessel is divided into two sections and is separated by an internal head that is designed to withstand 25 psi pressure differential. The top section, which is 76 feet high and 60 inches inside diameter, is used for gasification. This section has a carbon steel shell monel clad, insulated with 9 inches of cast refractory and has a 37 inch ID Incoloy 800 internal shroud which extends halfway up the gasifier section. The char cooler section is located below the gasifier section. This section is 25 feet high, 30 inches in diameter, is uninsulated and of carbon steel construction.

Both sections of the gasifier operate with fluidized beds. Steam and oxygen are introduced into the gasifier section through the plenum zone which is located just above the internal head. This flow is then distributed into the gasifier through an Incoloy 800 cone containing 128 nozzles. Steam only is used to fluidize the char cooler section. The steam enters through a similar but smaller cone which is located in the bottom head of the char cooler.

Coal is fed to the gasifier by pneumatic transport from a pressurized Petrocarb lock hopper system using carbon dioxide. In the Synthane process, approximately 65% of the coal feed is converted to gas. The product gas resulting from the gasification process passes overhead through an internal cyclone into a gas scrubbing section and then to process units that maximize the production of methane. The char is withdrawn through the bottom of the gasifier cone through a standpipe and trickle valve to the char cooler. From the char cooler, the char is withdrawn by differential pressure through a 1 inch line to a vessel where it is slurried with water and then transferred to the filter area for dewatering and disposal as landfill.

Gas was first produced by the SYNTHANE Plant in July of 1976. As of this date, 2,590 tons of coal have been processed through the plant. The gasifier has been operated at 600 psi and at bed temperatures varying from 1300°F to 1550°F.

GASIFIER PRESSURE CONTROLS

The gasifier was designed with the following pressure and level instrument control systems:

Bed Level Indication in Gasifier and Char Cooler Sections

Bed level in the gasifier and char cooler sections, as shown in Figure No. 2, is determined by utilizing two vertical dip tubes which are located within the fluidized beds and of known distance apart and a third dip tube which is located above the bed. Differential pressure instruments of 100 inch range are installed across the legs. One d/p transmitter is located across the dip tubes that are separated by 6 feet and another d/p transmitter is located across the lower dip tube and a dip tube which is above the bed height. The dip tubes are purged with inert gas and are made of Incoloy 800 pipe. The difference in pressure resulting from the fluidized beds across the 6 feet spans is sensed by PDT-203 and PDT-205. This reading is used to determine the bed density in the gasifier and in the char cooler. The difference in pressure across the taps, PDT-202 and PDT-204, measures the pressure exerted by the full bed heights. Assuming that the fluidized beds are uniform in density, the bed heights in each section are then determined by calculating the ratio of the readings of the total bed height and the bed density indications and multiplying this value by the known distance of 6 feet. The calculation of bed heights and densities are displayed and refreshed on the Computer CRT in the Control Room.

Gasifier Pressure Control

The pressure control system for the gasifier is presented in Figure No. 3. The overhead pressure of the gasifier was originally designed to be sensed by pressure transmitter PT-206 which was located in piping some distance downstream from the gasifier. Between this sensing point and the gasifier, there were several vessels through which gas would pass before the pressure would be recorded. Prior to startup, the mode of gasifier pressure control was changed. Pressure transmitter, PT-295, was installed on the top portion of the gasifier. The signal from PT-295 was then transmitted to the Control Room where PIC-295 controls a valve that is located in the outlet line of the gas scrubbing system.

The differential pressure between the gasifier and char cooler is designed to be controlled by sensing the pressure between the char cooler and gasifier sections on a -10 to 0 to +10 psi differential pressure instrument, PDT-257. The output of this instrument is transmitted to the Control Room where PDIC-257 sends a signal to a control valve, PDCV-202, which is located in the effluent gas line of the char cooler. The instrument senses changes in the gasifier or char cooler

pressure and the signal is transmitted to PDCV-202 to adjust the char cooler pressure so that the proper differential is maintained. Because the gasifier has an internal head that will withstand only 25 psi in pressure differential, close control of the pressure differential between the plenum chamber, the gasifier, and the char cooler is critical to the operation.

Bed Level Control in Gasifier

The level of the fluid bed within the gasifier reaction zone, as shown in Figure No. 4, is designed to be controlled by PDIC-202 which takes its signal from PDT-202. This instrument, as well as the char cooler differential pressure controller PDIC-257, operates PDCV-202. An alarm indicating a high pressure differential and a manual switch are provided to allow the operator to switch from level control to pressure differential control in the event that a high differential in pressure results, or if a high bed level is noted in the char cooler. When placed on automatic, the PDIC-202 controller senses a high bed level and opens the control valve, PDCV-202. This causes the char cooler pressure to drop resulting in more char flow through the standpipe from the gasifier to the char cooler. Conversely, if the gasifier fluid bed level drops too low, PDCV-202 closes causing the char cooler pressure to increase thus slowing or stopping the flow of char from the gasifier.

Bed Level Control in the Char Cooler

Bed level control in the char cooler, as shown in Figure No. 5, is designed to be adjusted by the bed level differential signal from PDIC-204 which controls the action of slide valve PDCV-204 located in the outlet line of the char cooler. Char is moved from the char cooler to the char slurry tank by maintaining a constant pressure differential between the two vessels using steam as the transport medium. The char is then transferred from the char slurry tank to the char filter area by pressure letdown.

ORIGINAL INSTRUMENT INSTALLATION

Although the concepts of the instrument design for the SYNTHANE gasifier were sound, simple and straightforward, the pressure sensing systems and controls, as installed, were essentially inoperable. The typical instrument installation, as originally installed, is shown in Figure No. 6.

As seen in the drawing, high pressure inert gas was used to provide instrument purge. The purge system which was provided consisted of a configuration of block valves, a check valve, and a rotameter. A connection was made from the purge line to the pressure transmitter which was mounted below the sensing taps.

The system as designed was inoperable for the following reasons:

1. The bed level and density instruments were sensitive to small variations in purge flows.

2. The purge lines plugged with solids when the flows were reduced to levels that did not affect the transmitter indications.

3. Steam migrated up the sensing lines and filled the pressure transmitter legs with condensate.

4. Rotameters stuck due to dirty CO_2 and failed to operate.

5. The check valves were spring loaded and put an uneven back pressure on the pressure transmitters.

6. The location of pressure taps was poor. Too many instruments were connected to the same tap. Some taps were located in dead legs and in areas which were subject to fouling.

7. Instrument range control was too wide for accurate control.

INSTRUMENT REVISIONS

Major changes were made to all of the pressure sensing instruments within the first three months of operation. In a stepwise manner, each of the problems mentioned was overcome. The primary goal emphasized the necessity of gaining pressure sensing reliability. Modifications involved relocating transmitters above the taps, relocating sensing lines, purchasing new rotameters, adding needle valves to the rotameter stations, replacing the spring check valves with bonnet lift check valves and finally, redesigning the entire purge stations.

During the first phase of redesign, all of the pressure sensing instruments were modified as shown in Figure No. 7.

The specifics, as shown, are:

1. All d/p transmitters were relocated at least 10 feet above the pressure taps.

2. The holes in the outlet of the dip tubes were enlarged from 1/4 to 1/2 inch.

3. The CO_2 purges were changed to enter directly into the purge tubes to minimize the effect of purge on the instruments.

4. The check valves were removed from the lines to the pressure transmitters and were relocated in the CO_2 purge lines.

5. The purge rotameter bypass stations were provided with double block and bleed valves.

6. Needle valves were provided for rotameter control.

7. All sensing lines were sloped back to the gasifier and all pockets were removed.

This interim design increased sensing reliability considerably. Subsequently however, it was determined that additional reliability could be achieved by purging the complete systems from the pressure transmitters to the outlet of the dip tubes. These revisions shown in Figure No. 8 include the following:

1. Rotameters with a range of 0-500 SCFH were installed on each sensing line at the pressure transmitters.

2. A continuous CO_2 purge was injected at each pressure transmitter leg. This purge was normally 230 SCFH based upon a rate of 1 foot per second through the opening in the purge piping.

3. Needle valves were installed at each rotameter for control.

4. 1/8 inch Capillary tubes approximately 25 inches long, were installed between the rotameters and the sensing lines to help control flow of CO_2 purge.

5. Condensate pots were installed in the sensing lines at the gasifier flanges.

6. The CO_2 purge connections at the vessel taps were converted to blast purges and are now used in case of instrument malfunction.

The instrument revisions, as described in Figure No. 8, have given the SYNTHANE Plant reliable bed level, density and pressure indications. Prior to startup of each gasifier run, scheduled sequence checks are made to assure compliance with the test directives. This includes setting of the purge rates and zero checking of bed level and density instruments to the control board and computer.

As instrument reliability was achieved, more attention was given to improving process control. Improved gasifier pressure control was achieved with PT-295 by adding another pressure transmitter of narrower range. For startup purposes the full range of 0 to 1200 psi pressure transmitter that was originally provided is used. When the vessel is up to operating pressure, the parallel unit is placed in service. Since the gasifier is being operated at 600 psi, the parallel pressure transmitter is ranged from 500 to 700 psi.

Further improvement in gasfier pressure control was also achieved by providing a similar parallel pressure transmitter for the high pressure steam pressure controller PIC-338 which controls the steam pressure to the gasifier. The parallel instrument was ranged from 600 to 750 psi such that a constant 100 psi differential over the gasifier pressure could be obtained.

As shown in Figure No. 9, a major change has recently been made to control the flow of char from the gasifier. The trickle valve in the standpipe between the gasifier and char cooler has been modified for automatic control. A valve actuator has been mounted on a flange on the

outside of the shell of the char cooler with the valve stem extending through the char cooler and attached to the flapper of the trickle valve. The PDIC-202 bed level controller in the gasifier section now operates this trickle valve and the differential pressure controller, PDIC-257, controls only differential pressure between the gasifier and char cooler.

In addition to the revisions covered in the current design, it should be pointed out that cold weather conditions can and do compound all the problems encountered. The need for upgrading the steam and electrical tracing of transmitters and process instrument tubing for freeze protection became apparent and this task was undertaken and accomplished.

During the course of plant operation, it was also found that gas used for purge must be free of particulates. It was necessary to install suction filters on the CO_2 compressors in the SYNTHANE plant not only to minimize compressor wear but to keep the purge lines free of solids that can plug rotameters and lines.

CONCLUSIONS AND RECOMMENDATIONS

In future scaleup of Coal Gasification Plants, or in existing facilities where pressure measurement problems of this nature may exist, the following suggestions are made:

1. The inert gas source used for purging should be properly filtered to maintain lines free of particulates.

2. Purge tap openings of 1/2 inch are recommended with purge velocities of 1 foot per second.

3. Transmitters should be located at least 10 feet above the pressure taps and lines should slope and contain no pockets.

4. Purging from the pressure transmitters through the entire sensing line will keep the sensing lines clear of condensate and particulates.

5. Condensate pots at the nozzle taps will collect any condensate which forms in the system and provide a means of blowdown.

6. The location for pressure taps should be chosen away from possible points of contamination.

SYNTHANE GASIFIER

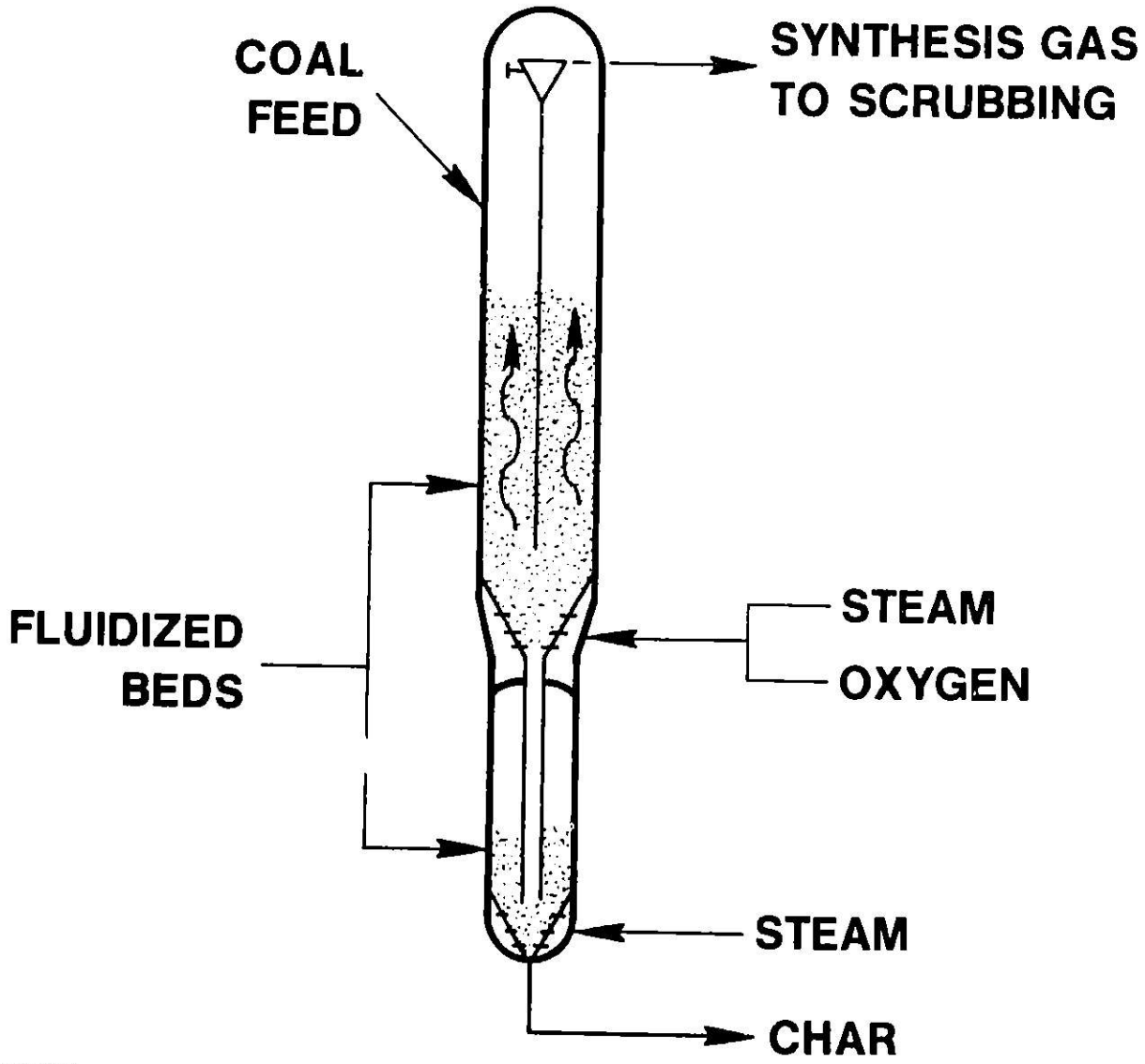


FIGURE 1

SYNTHANE GASIFIER BED LEVEL INDICATIONS

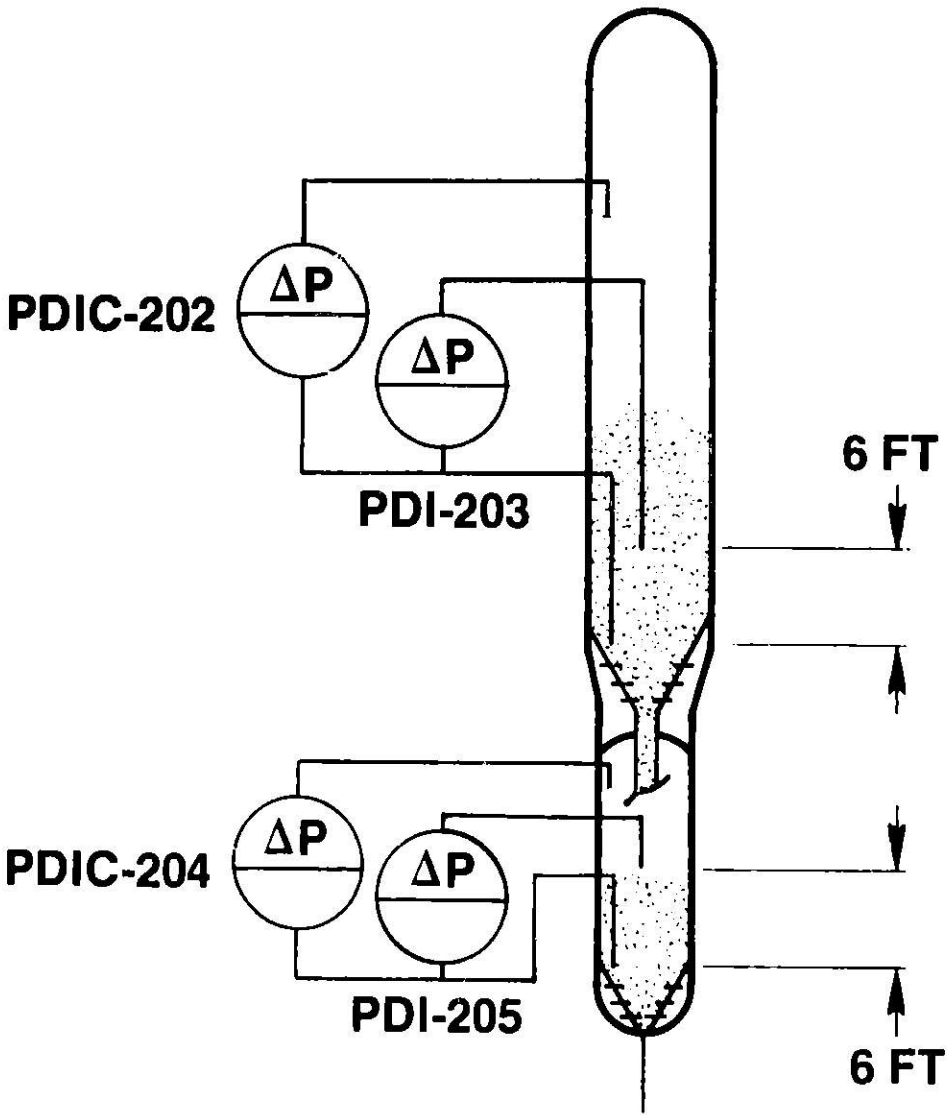


FIGURE NO. 2

SYNTHANE GASIFIER
PRESSURE CONTROL SYSTEMS

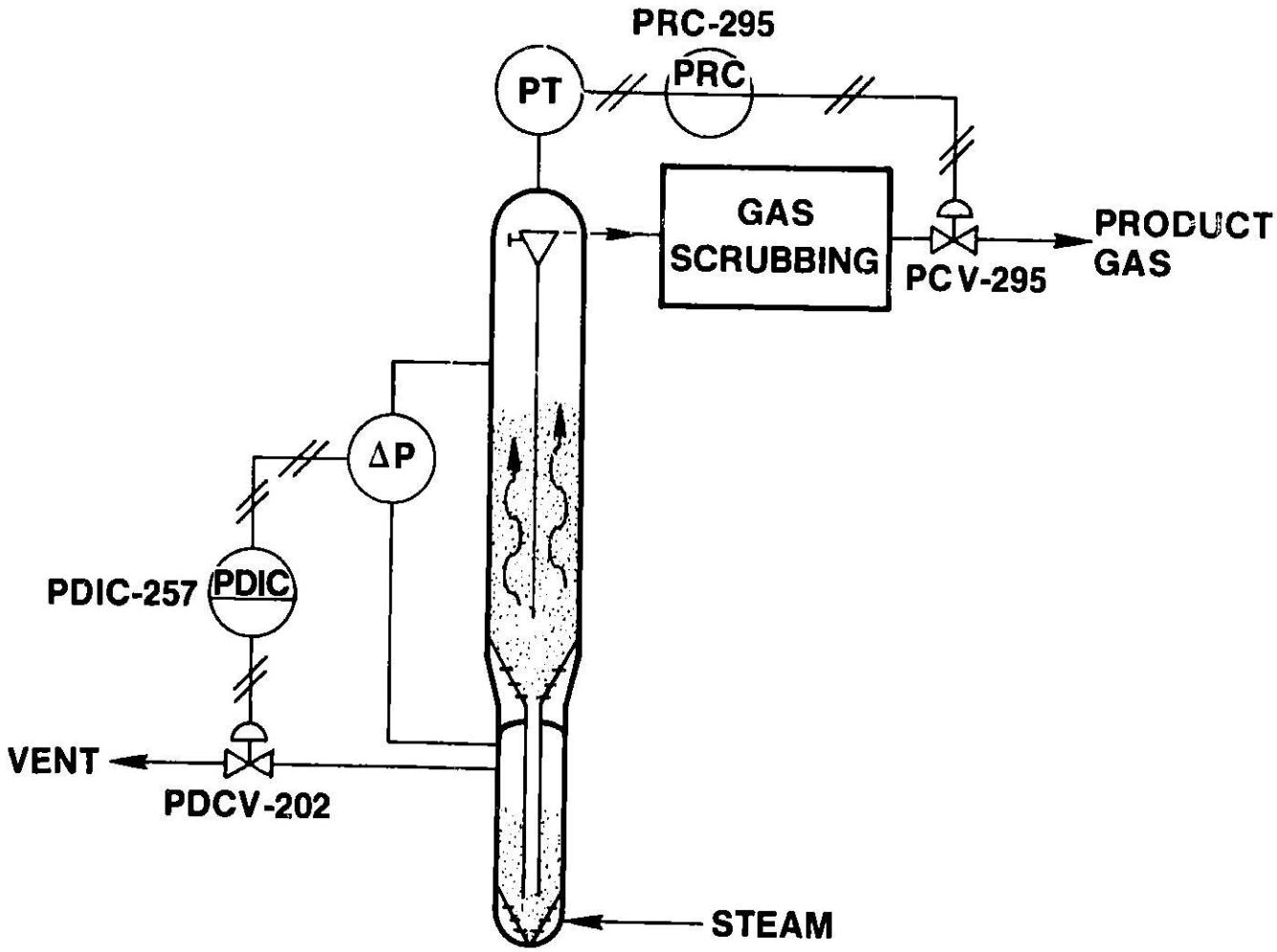


FIGURE 3

SYNTHANE GASIFIER
GASIFIER BED LEVEL CONTROL

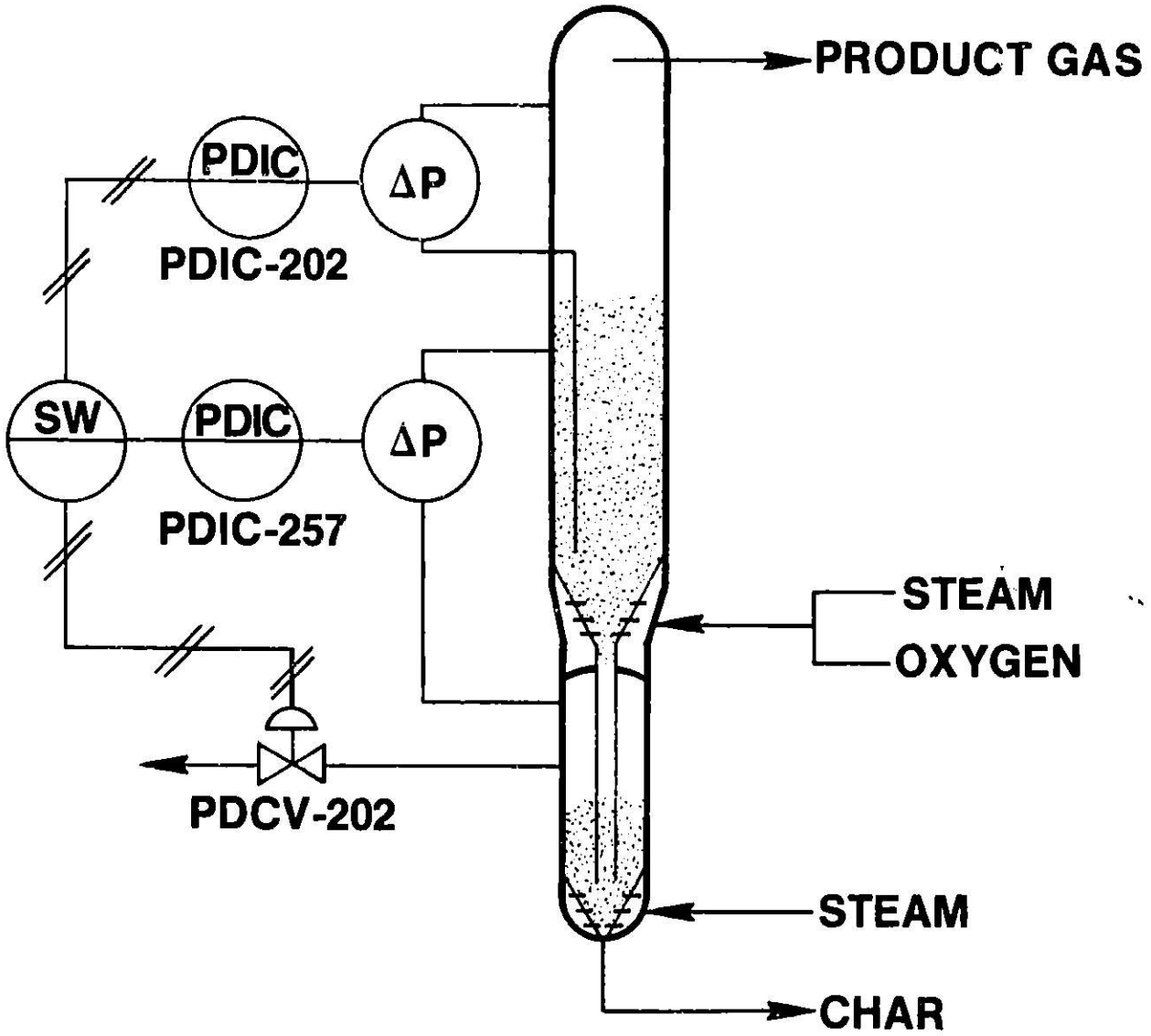


FIGURE 4

SYNTHANE GASIFIER CHAR COOLER LEVEL CONTROL

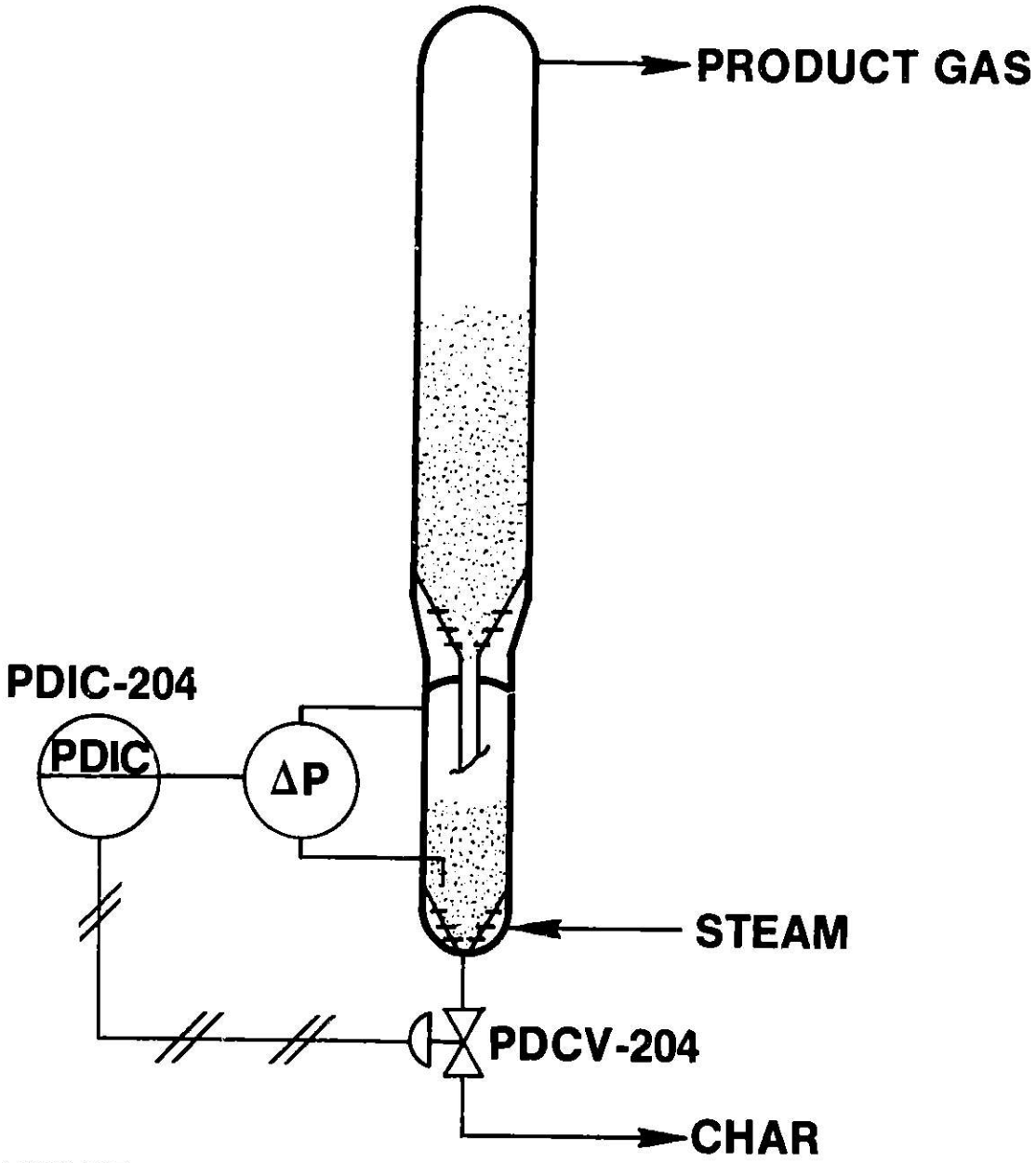


FIGURE 5

SYNTHANE GASIFIER ORIGINAL PRESSURE TRANSMITTER INSTALLATION

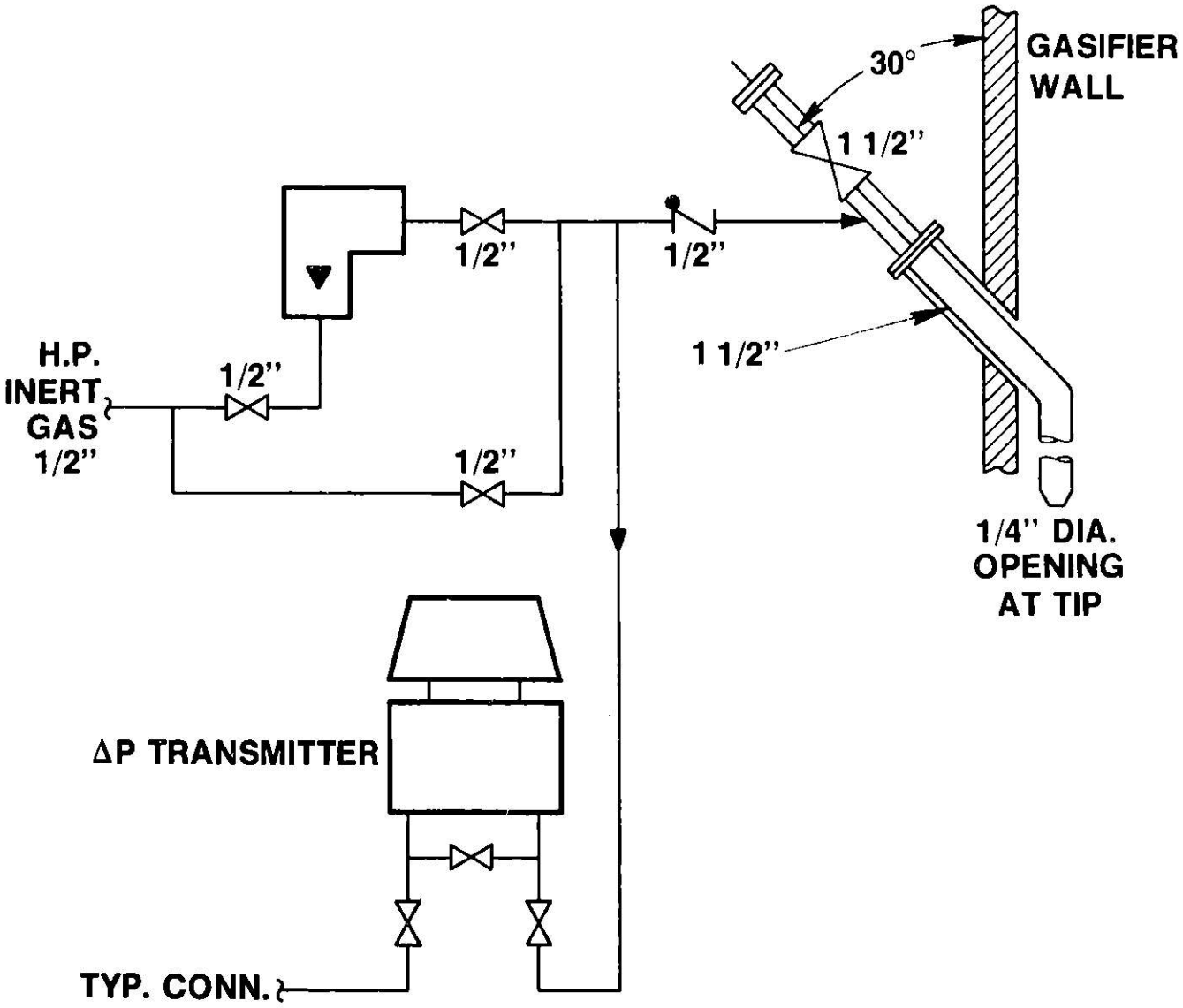


FIGURE 6

SYNTHANE GASIFIER INTERIM TRANSMITTER INSTALLATION

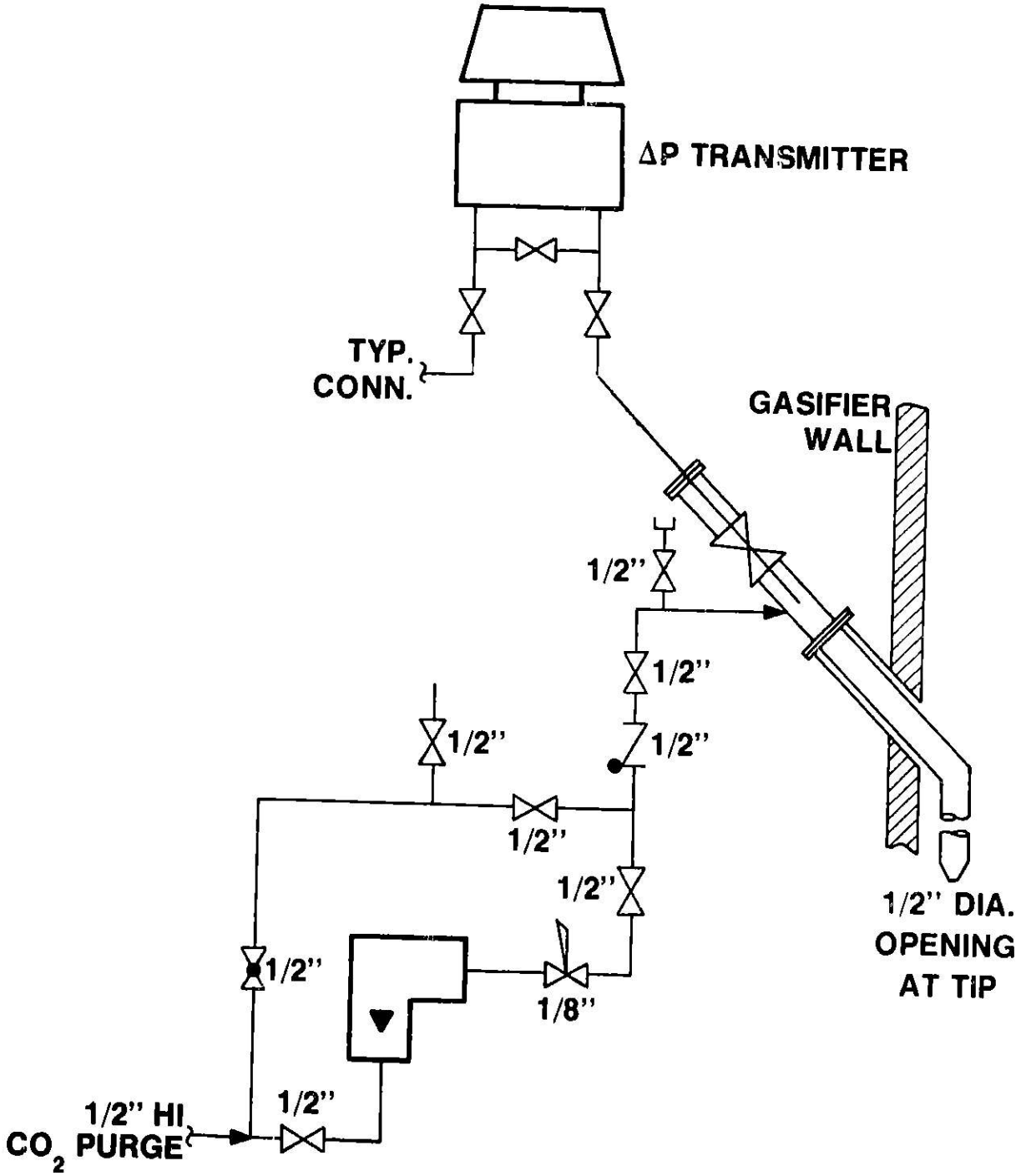


FIGURE 7

SYNTHANE GASIFIER
CURRENT TRANSMITTER INSTALLATION

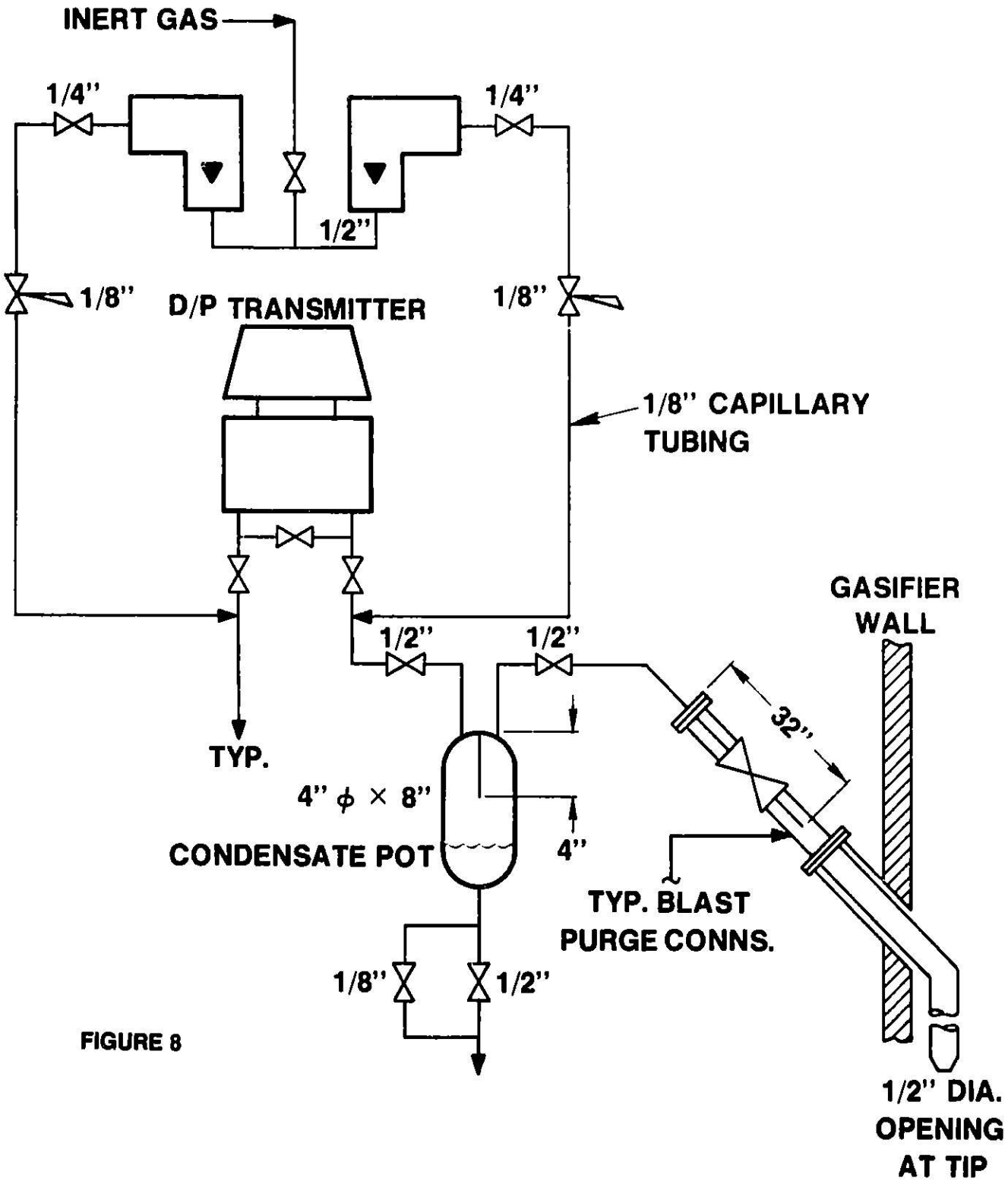


FIGURE 8

SYNTHANE GASIFIER
MODIFIED GASIFIER
LEVEL CONTROL

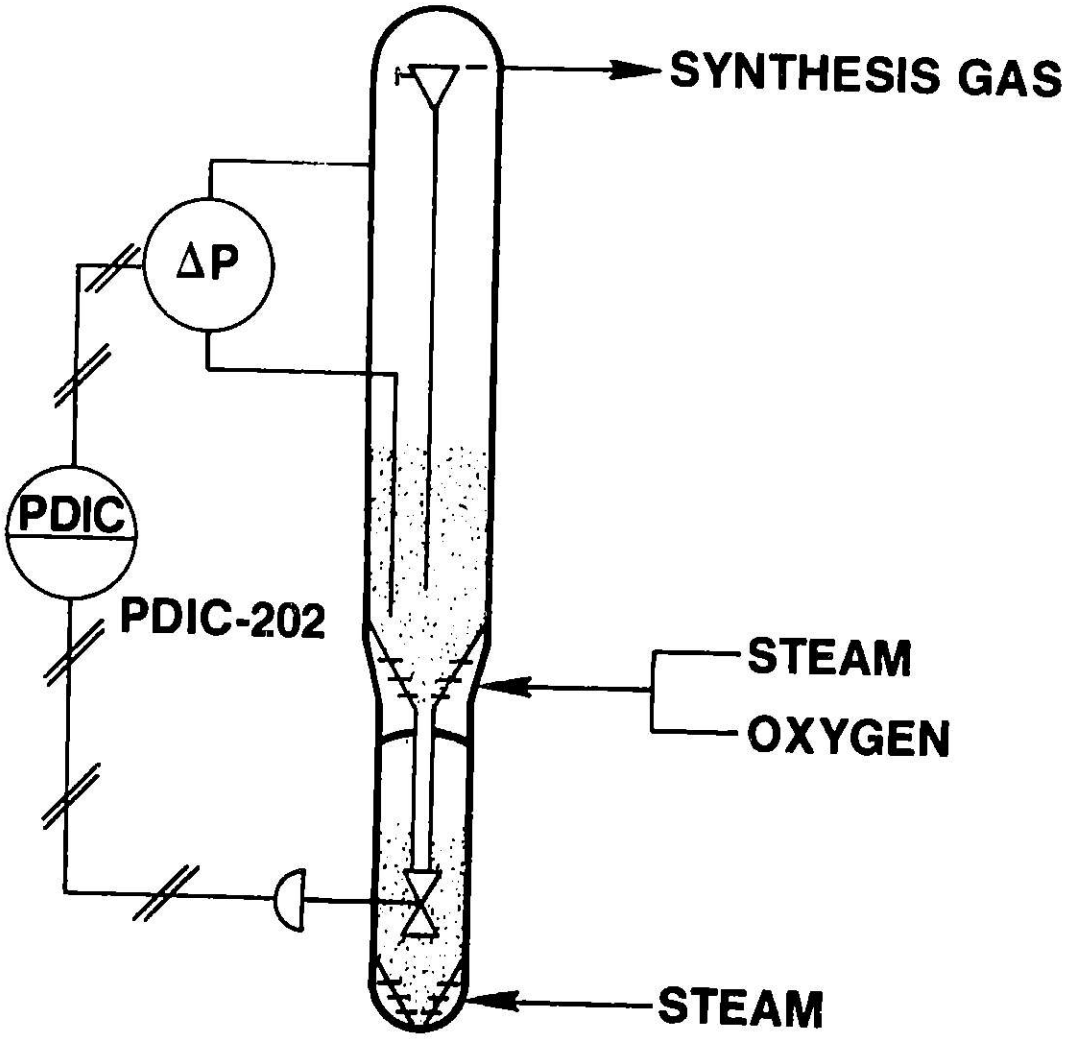


FIGURE 9

QUESTIONS AND ANSWERS

D. M. Bailey

The Lummus Company

W. E. Shannon, Lockheed Palo Alto Research Lab.

Q. What total lummus effort (man-months/man-hours) was required to:

1. Analyze synthane control system problems,
2. Remove, install and checkout the modified control system.

A. In answer to the first part of the question, this was done at the plant with plant people. As for the second part of the question, that was also done completely by the people at our facility. We did it in steps. During plant outages, we would make changes, then run again and make more changes. I cannot tell you actually how much time was required but it was fairly extensive to get the problems resolved.

W. S. Su, Stearns-Roger, Inc.

Q. Please explain your approach on temperature measurement.

A. In a gasifier, we have eight sheath thermocouples made of 310SS that extend into the bed area approximately every two feet. The gasifier also has two thermocouples that are located within a Hastalloy C thermowell. The thermocouples also give a good indication of bed level. To date, we have not had any serious failure problems.

C. K. Sanathanan, University of Illinois, Chicago

Q. Did your control system design result from system models or did you design them by some practical guesses?

A. We did this by what we thought were best guesses. We analyzed the problems and then decided what we thought was the best approach. I am sure that there can be some improvements to this system as it is presently installed, but I can say what we now have gives us excellent reliability.

J. O. Hougen, University of Texas

Q. The diagram of the final ΔP system-as shown-appears to offer the opportunity to effectively partially bypass the d/p cell. Please clarify.

A. I do not understand that question. (It was later discussed that bypass cannot occur because of the following:)

1. The purge is 150 psi over gasifier pressure.
2. The purge comes off separate lines. Figure 8 is only a schematic.
3. Check valves are installed and not shown in the sketch.

R. G. Corley, Monsanto Company

Q. Please identify DP transmitters and the calibrated ranges used.

A. The ranges very depending upon the application. The bed level instrumentation has 0-100 inches. Bed density instrumentation is 0-50 inches pressure differential between the gasifier and the char cooler has minus 10 to 0 to plus 10 psi.

F. Bondy, Foster Wheeler Energy Corp.

Q. Did you recover and clean up CO_2 vent gases from Petrocarb lock hopper system. If so, what equipment did you use for cleanup?

A. The Petrocarb system has been working very well. We have had very few problems with this system. The vents from the Petrocarb system go directly to our thermal oxidizer. The Petrocarb system has three vent valves that depressure at different pressures. When you are at 600 lbs. the first valve which is the smaller valve opens up and depressure the vessel to 170 psi, then the next valve opens up and it depressures down to around 30, and the last valve opens and depressures at 5 psi. To prevent rapid depressurization of fines entrainment, what we had to do was to install smaller orifices at the valve locations.

Q. Do you have any quantitative results on solids in vent gas directly from lock hopper systems?

A. No quantitative results have been taken. The only thing I can say is that is very minimal as long as the system is operating properly. We have operated with the Petrocarb System vented directly to the atmosphere and although some dust vented to the atmosphere, it was not very noticeable.

B. G. Liptak, Liptak Associates

Q. What problems did you have with lock hoppers?

A. The Synthane Plant is actually built with a lock hopper system for char removal which I did not show you. At the very start of the Plant, during the pressure testing phases, the lock hopper valves would not hold and were sent back to the supplier for remodification. The Plant therefore went to the standby slurry system which we are currently using, and this system is working quite effectively. We have not had very many problems with the lock hoppers in the Petrocarb system. Some problems occurred with vent valves which we were able to overcome. We found that these valves were operating too quickly and forced the seats back into the body unevenly which caused them to jam in the body of the valves. When we slowed the valve actuators, the valves operate very well.

V. J. Orphan, Science Applications

Q. How accurately can you measure bed level and density? How uniform is the bed? How do you determine the uniformity?

A. Actually, at present, we are adding a second probe into the gasifier bed. The first probe we have is at a six-foot level. We are adding a second probe that will go from a six-foot level to the twelve-foot level in order to determine bed uniformity. We really do not know if the bed is uniform but we have assumed that the bed is uniform in density. The accuracy of bed level calculations we feel are pretty good. This is in view of the fact that the thermocouple readings in the bed agree with the bed levels that we calculate.

Chairman

Q. Getting back to Dr. Hougen's question, if we may for just a moment. I believe the question is, if I understand it properly, looking at the last diagram, appears to offer the opportunity to effectively partially bypass the dp cell. I presume that this is by closing a valve inadvertently.

A. The instrument is placed in service by first establishing purge flow and then adjusting the purges to zero out the instrument because of the difference in length of the dip legs. No bypassing occurs because:

a) the purge pressure is 150 psi above gasifier pressure,
b) the purges come off separate headers, not as shown in schematic Fig. 8.
c) check valves are installed in the pruge line that are not shown in the figure.

BI-GAS HIGH TEMPERATURE THERMOCOUPLES -- DESIGN CONSIDERATIONS AND OPERATING EXPERIENCE

N. D. Pitcher
Stearns-Roger Incorporated
Homer City, Pennsylvania

BI-GAS HIGH TEMPERATURE THERMOCOUPLES
DESIGN CONSIDERATIONS AND OPERATING EXPERIENCE

Norman D. Pitcher
Stearns-Roger Incorporated

INTRODUCTION

Coal Gasification environments place severe operating conditions on materials and components. The most severe environment is found within the gasification zone where the high temperature, high pressure, erosive and corrosive environment can quickly destroy conventional materials and components.

One of the more critical components in the control/monitoring of the gasification process, is the high temperature instream thermocouple. In order to accurately sense the gas/particle stream temperature, the thermocouple probe must be placed into this severe environment and still provide reliable measurement over long periods of time without replacement.

This paper discusses the development progress and operating experience of the BI-GAS high temperature thermocouples to date. Areas discussed are:

1. Review of environmental conditions and functions of the BI-GAS thermocouples.
2. Design considerations and component requirements for high temperature thermocouples.
3. Operational experience and development progress of the BI-GAS thermocouple.

BI-GAS THERMOCOUPLES

Figure 1 illustrates the locations of the BI-GAS gasifier thermocouples. The severity of the environment can be classified according to the stage locations. Stage I thermocouples 10, 11, 12 operate between 2500°F-3000°F under slagging conditions with a temperature difference less than 50°F between the three readings. A hot char, steam, methane/oxygen mixture is injected into Stage I via the three char burners which are positioned at the same level as No. 12 thermocouple.

Stage II thermocouples 2, 3, 5, 6 are positioned at approximately 5 foot spacings and operate between 1500-2000°F. A coal/steam/recy le gas mixture is injected into the lower section of Stage II via the two coal injectors. Since the majority of the gasification reactions occur in Stage II, it is considered that Stage II atmosphere is more corrosive than Stage I.

Table I lists the approximate composition of gas leaving Stage II.

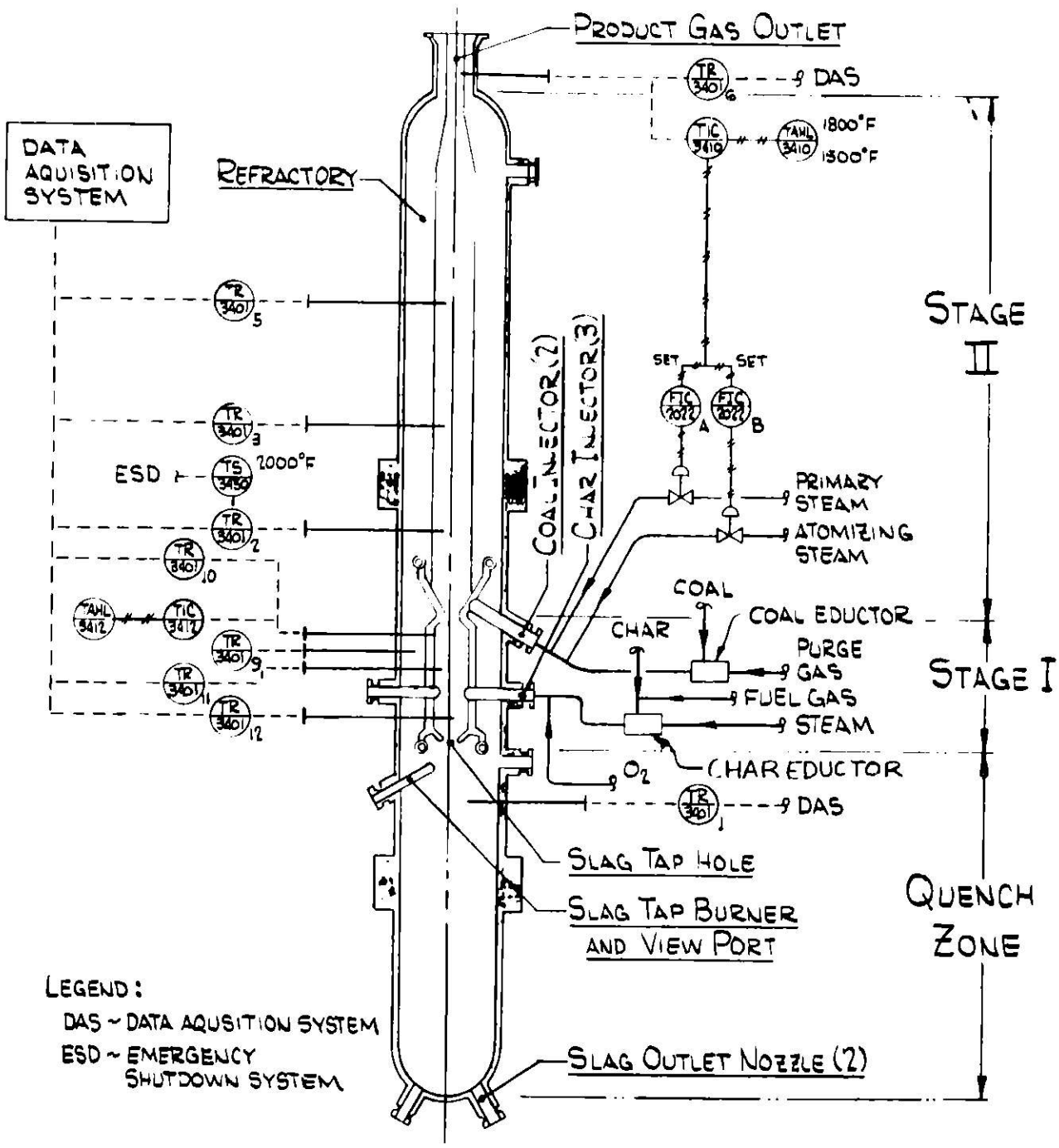


Fig. 1. BI-GAS Gasifier Thermocouples

TABLE I

Component	Composition
CO	14.1
CO_2	10.2
H_2	19.4
H_2O	51.6
CH_4	4.3
H_2S	0.3
N_2	0.1

In addition to the Stage instream thermocouples, thermocouple no. 9 is positioned in the annular region between the barrel and shell cooling coils and no. 1 is in the vapor space of the slag quench section. No. 9 thermocouple operates at about 450°F, which is the cooling coil temperature, and no. 1 senses the quench water temperature of approximately 100°F.

OPERATING FUNCTIONS
(Figure 1)

All the gasifier thermocouple signals are tied into (1) Control Room Pen Recorders and (2) Computer Maintained Data Acquisition Systems.

Under the present operating mode, Stage I thermocouples are monitored and char burner firing and steam rates are manually adjusted to keep slag flowing through slag tap hole (2500-3000°F). The feasibility of maintaining Stage I temperature by controlling O_2/char (fuel gas) to the char burners via a cascading temperature controller will be evaluated in future operations.

Stage II thermocouple No. 2 is tied into the emergency shutdown system (ESD), which will automatically shut down the gasifier if Stage II temperature exceeds 2000°F. The Stage II temperature is automatically maintained at 1500-2000°F by controlling the steam flow to Stage II via a cascading temperature controller.

THERMOCOUPLE DESIGN PARAMETERS

In developing a thermocouple for a coal gasification environment, there are many operating design conditions which must be evaluated. The design must not only obtain accurate readings, but must result in long term reliability in the severe environment. This latter requirement places considerable emphasis on proper material selection. The design parameters which must be considered in developing the BI-GAS thermocouple are:

1. High Temperature

   Normal operating temperatures will be as high as 3000°F in Stage I. Materials must have high melting points and sufficient high temperature strength to avoid failure.

2. High Pressure

   Normal operating pressures between 700-1500 psig.

3. Sulfidation Attack

   The 0.3% H_2S content of the BI-GAS environment will result in sulfidation attack of various metals.

4. Hydrogen Attack

   The 20% hydrogen content of the environment will result in hydrogen penetration of various metals resulting in loss of strength.

5. High Temperature Oxidation

   Although the BI-GAS environment is considered reducing, localized oxidizing conditions could possibly occur during start-up periods and during normal operation.

6. Erosion

   Erosion may be significant, especially in Stage I where the thermocouples are exposed to the tangential char flow in the region of the char burners.

7. CO, H_2, Steam Oxidation/Reduction Reactions

   The presence of CO, H_2, and steam may promote various oxidation/reduction reactions.

8. Slag Attack

   The slagging environment of BI-GAS Stage I will necessitate the selection of materials, which have a high resistance to slag attack which will result in penetration of or complete loss of materials.

9. Thermal and Mechanical Shock

   Components should have good thermal and mechanical shock resistance. These requirements will place severe restriction on ceramic and cermet type materials.

DUAL WELL THERMOCOUPLE COMPONENTS

The high temperature, erosive and corrosive atmosphere of the gasifier necessitates the use of a protected thermocouple for the BI-GAS Process. The specific components which go into the construction of the protected thermocouple must be selected after taking into consideration, the nine design parameters previously discussed. In general the dual well thermocouple is constructed of the following component parts.

Thermocouple Components

1. Wire Type

Table II provides temperature ranges for various thermocouple wires. The 3000°F operating temperatures in Stage I requires the use of tungsten/rhenium wire. Platinum/rhodium type B wire (3100°F) was considered; however, short term temperature excursions exceeding 3000°F in addition to type B susceptibility to hydrogen attack makes this wire unsuitable for BI-GAS service. Although all three tungsten/rhenium wire combinations can operate to 4200°F, the 5% Re combination was selected because of the inherent brittleness of unalloyed tungsten. Tungsten is also advantageous because it has good resistance to hydrogen attack which could diffuse through the outer layer. One disadvantage of tungsten rhenium wire is that it undergoes rapid deterioration in oxygen environments. However, with the exception of H_2 diffusion, the dual well construction is designed to protect the wire from gaseous attack.

TABLE II

Approximate Thermocouple Wire Temperature Limits

Type of Wire	Temperature Limit °F
Iron-Constantan (Type J)	1400°F
Chromel-Constantan (Type E)	1600°F
Chromel-Alumel (Type K)	2300°F
Pt/Pt 10% Rn, Pt/Pt 13% Rn (Type R,S)	2700°F
Pt-30% Rn/Pt 6% Rn (Type B)	3100°F
W/W 26% Re, W-5% Re/W-26% Re W-3% Re/W 25% Re	4200°F

2. Wire Size

There are no specific guidelines for the selection of thermocouple wire size. However, as a rule of thumb where fast response time is required, smaller gage wire should be used. Where long life is preferred, or for higher temperatures, heavier thermocouple wires should be selected. However, the effect of wire size on response time when compared to the effect of the dual sheath should be negligible. Table III lists recommended temperature limits for various sizes of tungsten/rhenium thermocouple wire. In order to achieve high reliability, .010 - .020" wire should be selected with .020 preferred.

TABLE III

Temperature Limits Tungsten/Rhenium Wire

Wire Diameter (in)	Temperature Limit °F
.003	3200
.005	3600
.010-.020	4200

3. Junction Type

Although a grounded type junction provides better reponse time, an ungrounded junction was selected to provide better reliability. The ungrounded junction should also eliminate potential failure from sheath/wire thermal expansion and sheath/wire material interaction problems. The welded junction of refractory wires is quite brittle and highly susceptible to breakage. However, thermocouple vendors have generally resolved this problem through proprietary weld/wire wrap techniques.

4. Inner Sheath Material and Coating

The inner sheath serves as the secondary protection for the thermocouple wires. In the event of complete or partial failure of the outer (primary) protective well, this inner sheath should be capable of providing some degree of protection and structural support to the thermocouple. The inner well should have some resistance to chemical, oxidation/reduction attack, and good high temperature strength. In addition, the inner sheath must have chemical and physical compatibility with the insulation being used.

Table IV provides some temperature and environmental limitations for several high temperature sheath materials. Of these materials, only molybdenum is suitable for a reducing environment. In addition, molybdenum is unaffected by hydrogen and has good high temperature strength. Molybdenum is very sensitive to oxidation above 1000°F; however, the use of a ceramic coating should provide oxidation protection.

The selection of the sheath diameter is a compromise between the good response time of a small diameter sheath versus the better high temperature strength of larger sheath. However, when a dual sheath thermocouple is utilized, the affect of sheath size on the total response time should be minimal. Thermocouple vendors generally offer 1/8" diameter sheaths with .010" wire and 3/16" diameter sheaths with .020 wire. Based on reliability advantage of the larger wire and larger sheath combination, the larger sheath should be selected.

TABLE IV

High Temperature Sheath Materials

Material	Maximum Operating Temperature °F	Environment
Molybdenum	4000	Inert, reducing
Tantalum	4500	Inert
Platinum-Rhodium Alloy	3050	Oxidizing

5. Insulators

The insulator material selected must have a high maximum operating temperature, good thermal characteristics, and physical and chemical compatibility with the thermocouple wires and sheath. Since impurities can cause bridging of the wires at high temperatures and reduction in useful maximum operating temperature, a high purity grade of the insulator selected should be specified.

Table V lists the temperature limits of three high temperature hard fired insulators. The Al_2O_3 is perhaps the best overall choice for the 3000 ^oF range primarily because it is compatible with W-Re-Mo and does not have the hydroscopic and toxic disadvantages of MgO and BeO respectively.

TABLE V

High Purity Insulation	Approximate Useful Temperatures ^oF	Remarks
MgO	3300	Hydroscopic
Al_2O_3	3400	Compatible with W-Re-Mo
BeO	4000	BeO dust is toxic when inhaled

6. Outer Well (Primary Protection Tube)

The outer well provides the primary protection for the thermocouple from the gasifier environment. The protection tube must be capable of withstanding the erosive/corrosive, high temperature environment of the gasifier, and ideally should minimuze the diffusion of various gases through its walls. Several of the critical design requirements which must be considered in selecting a protection tube are:

1. High melting point and good high temperature strength.
2. Good resistance to thermal and mechanical shock.
3. Resistance to chemical attack. (e.g., oxidation, reduction, slag attack, sulfidation)
4. Erosion resistance.

Unfortunately, it is difficult to find a material which can meet all of the above criteria. Table VI lists material selection data for various ceramic and metallic protection tubes. Although Table VI cannot be used for the selection of a specific material since it does not reflect performance in coal gas atmosphere, it can be used to select best candidate materials.

TABLE VI

Material Data On Protection Tubes

Material	Recommended Maximum Temperature °F	Remarks
Mullite (Silica-Alumina)	3000 O,R	-Good thermal shock -Good slag resistance
Alumina 99+%	3400 O, R	-Good slag resistance -High Strength -Gastight -Fair resistance to thermal shock
Silicon Carbide (Nitride Bonded)	3000 O, R	-Excellent resistance to thermal & mechanical shock
Chromium-Alumina (Cermet)	2600 O, 2600 R	-Excellent resistance to sulfides
Si_3N_4	2350 O, 3200 R	-Good thermal and mechanical shock resistance
Beryllium Oxide	4000 O, 4000R	-Fumes toxic -Reacts with steam
304 s.s.	1650 O, R	-Good scale and corrosion resistance
310 s.s.	2100 O, R	-Good scale and corrosion resistance
Inconel	2100 O, R	-Not recommended for sulfur environment
Molybdedum	900 O, 4000 R	
Tantalum	4000 O, Not recommended in reducing	

O - Oxidizing
R - Reducing

On inspection of Table VI, it appears that mullite, alumina, silicon carbide and molybdenum appear to be promising candidates for protection tubes.

Based on work conducted by Argonne National Labs, it is possible to gain some insight on how some materials can be expected to perform in coal gas environments.

Reference 1 investigated the suitability of various ceramic coatings and cermets for coal gasification environments. The study evaluated various coatings with respect to sulfidation, oxidation, erosion and application. Based on the survey, the following materials seem to be the best candidates for coal gas environments.

TABLE VII

Recommended Ceramic Coatings

Oxides	Carbides	Nitrides	Borides
Al_2O_3	SiC	Si_3N_4	TiB_2
Cr_2O_3	ZrC	TiN	HfB
ZrO_2	HfC	HfN	

This report also concluded that silicides do not offer protection against reducing, sulfidation, and erosion conditions of coal gas environments. The primary disadvantage of silicides is due to the fact that the coating will be attacked by the hydrogen and steam environment.

References 3 and 4 reported on the evaluation of various materials for slagging gasifiers. Test results cited in Reference 3 with a slag base/acid (B/A) ratio of 1.5 indicate that nitride and silica bonded silicon carbides performed poorly whereas high purity alumina Al_2O_3 and chromium oxide Cr_2O_3 and magnesium oxide composites performed well.

Gasifier tests to date using Rosebud coal indicate that the BI-GAS slag is slightly acidic and although the SiC failures cited in Reference 3 cannot be directly applied to BI-GAS, it does indicate the possibility of failure of SiC in BI-GAS Stage I due to slag attack.

Discussions with Argonne personnel indicate that SiC will have a high failure probability if surface is wetted by slag.[5] This position is supported by numerous failures of BI-GAS SiC protection tube. Failure analysis of several of these SiC wells indicated that SiC could be oxidized to SiO_2 by H_2O, CO and other O_2 containing gases. Normally, this SiO_2 would form a protective barrier against additional attack; however, the presence of steam and hydrogen in the coal gas environment may remove this protective layer.[1]

Based on the information discussed above and BI-GAS test results, it appears that SiC may not give good performance in BI-GAS Stage I and alumina or refractory metals may provide better service.

7. Immersion Lengths of the Thermocouples

The temperature which the thermocouple senses is dependent on the net heat transfer to the hot junction. The heat transfer to the probe is a function of the three modes of heat transfer.

1. Convection - Heat transfer between the hot gas and the thermocouple probe.
2. Conduction - Heat transfer along the mode between the immersed hot junction and the cold end.
3. Radiation - Heat transfer to the "cold" walls and the hot probe.

Convection is the primary mode and should be maximized, since it provides the best indication of the true gas temperature. Radiation and conduction impart errors and should be minimized. The simpliest approach to insure good readings is to immerse the probe into the stream far enough so that convection is maximized and conduction effect is minimized. Proper immersion depth also insures that the probe has penetrated the laminar flow region near the wall and is sensing the bulk stream temperature.

Typical "rules of thumb" specify that the thermocouple should be inserted four times the outer diameter of the protection tube. If the thermocouple must pass through a cooled wall, the insertion should be increased to ten times the diameter.

In the case of protected tubes, the application of such rules of thumb can often result in rather long immersion depths. For example, the BI-GAS probe with cooled walls results in a 6-1/4" immersion depth. This long immersion depth combined with the severe gasifier environment, places strict requirements on the probe material especially if ceramics or cermet tubes are used. By reducing the immersion length, the life of the hot probe should be increased through the reduction vibration and mechanical shock and erosion forces acting on the immersed probe.

To obtain the proper immersion depth, a heat transfer study was conducted on the probe using a "thin rod" model. The results of this study indicated that a probe length of approximately 3" will give accurate readings when using a ceramic type protection tube.

BI-GAS THERMOWELL/THERMOCOUPLE

The BI-GAS thermowell is shown in Figure 2. The design utilizes a cooling jacket surrounding the thermcouple sheath and a purge gas annulus for gasifier pressure instrumentation. The immersion depth is changed by adjusting a bored through tubing fitting at the back end of the thermowell.

Figure 3 depicts the first type of thermocouple which was installed in the gasifier. This thermocouple was an "off the shelf" thermocouple and utilized a silicon carbide hot section, with Al_2O_3 insulation in both the inner sheath and probe annulus, an 1/8" disilicide coated moly tube with .010" W5Re/W26Re wires. The vendor literature rated this thermocouple at 2900°F and suitable for "coal gasification reaction zones." The hot probe length on the initial supply of these thermocouples was specified at 6" probably using the "ten times diameter" immersion depth rule.

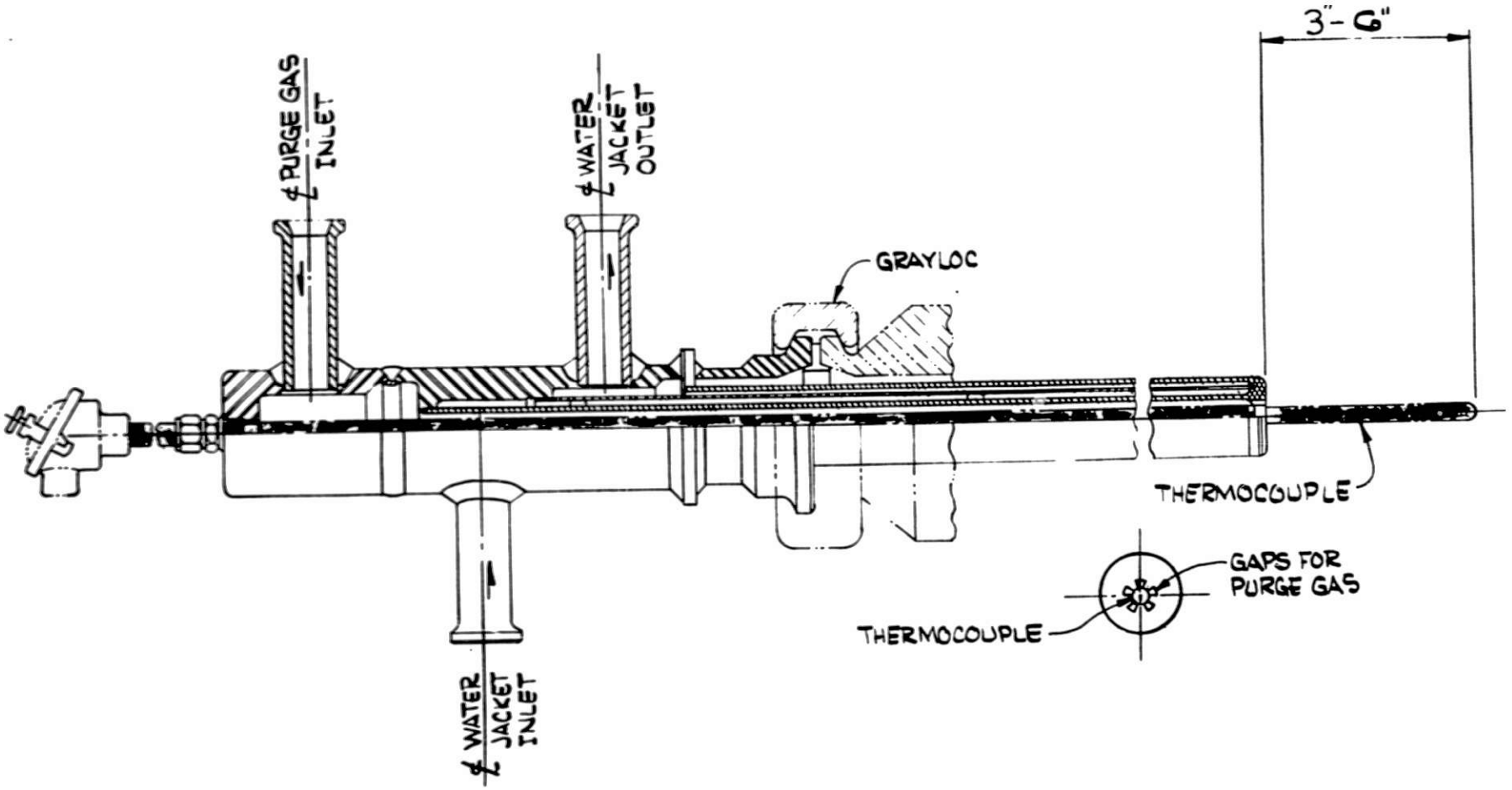


Fig. 2. BI-GAS Thermowell/Pressure Tap

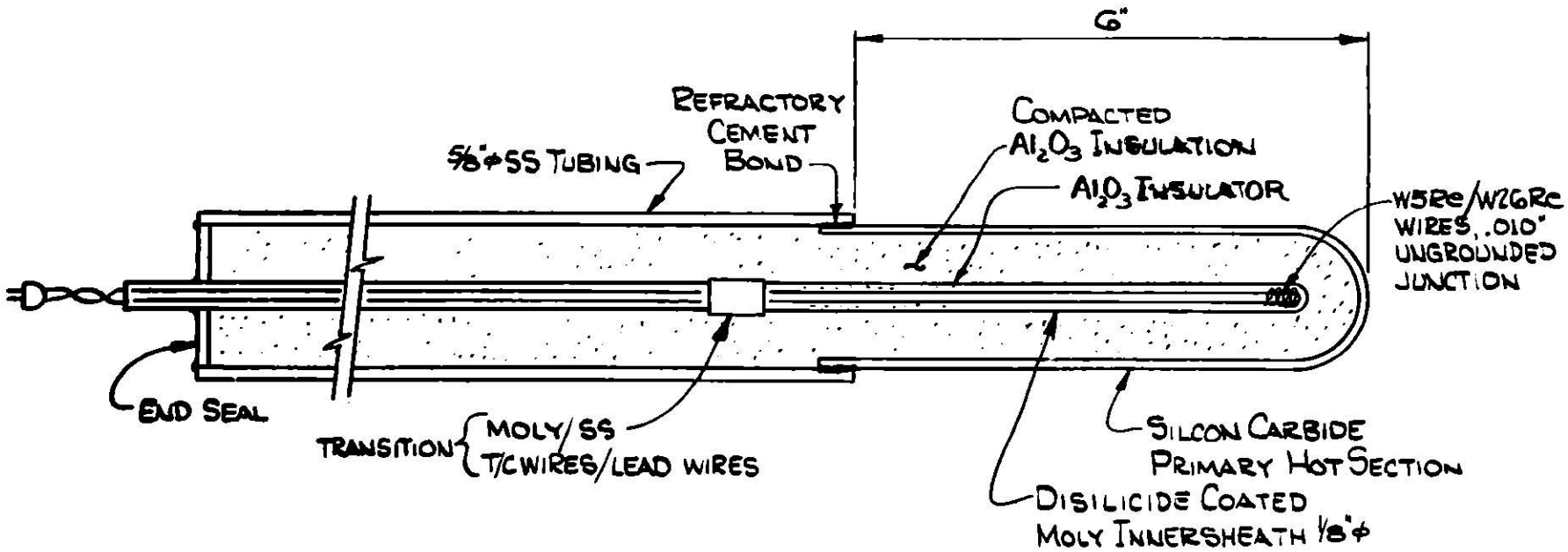


Fig. 3. Type SiC Thermocouple

OPERATING EXPERIENCE

REFRACTORY CURE OPERATION

Photograph No. 1 shows the condition of Stage I SiC outer wells which were exposed to 2800°F Max. during the refractory cure operation. No coal was fed during this operation and thermocouples No. 11 and 12 were immersed 1-1/2" and Nos. 10, 2, 3, 5 and 6 were inserted approximately 2-1/2". The SiC tips of Stage I thermocouples were reduced to 3/4 of their original diameter. The outer wells from Stage II locations 2, 3, and 5 were only partially eroded with silica globules on the surface. The SiC well on the upper most thermocouple No. 6 had been completely removed. All Stage I and Stage II thermocouples provided accurate readings throughout the operation and exposed moly sheaths appeared undamaged.

Failure analysis of the outer wells, reference 2, proposed the following failure modes and recommendations.

STAGE

Failure Modes

1. Eutectic metling involving SiC, SiO_2, Al_2O_3 - $MoSi_2$.
2. Partial high temperature oxidation of the SiC to SiO_2 by CO, H_2O or other oxygen containing gases.

Recommendation

Evaluate high purity alumina 99+% outer wells for Stage I.

STAGE II

Failure Mode

Oxidation of SiC to SiO_2 by CO, H_2O and other oxygen containing gases.

Recommendations

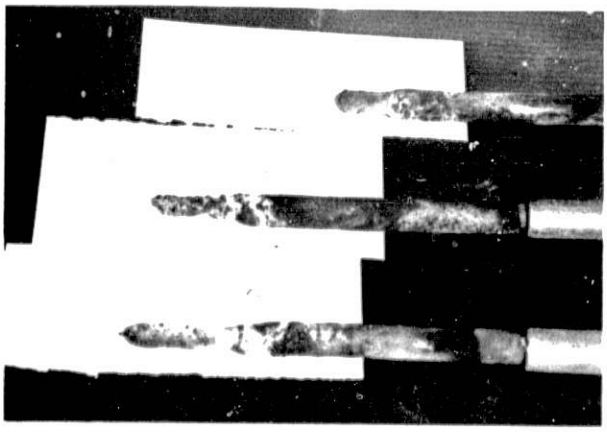
Evaluate metallic outer wells which will withstand the lower temperatures of Stage II.

1. 310 s.s. & 310 s.s. alonized.
2. Incoloy 800 alonized
3. 25 Cr - 35Ni
4. Hastelloy X

Based on these recommendations, alumina and metallic thermocouples were placed in order. The selection of alumina was later reinforced thorugh operation feedback from another gasification site which reported good results with alumina wells in a high temperature slagging type gasifier.[7]

COAL FEED TEST

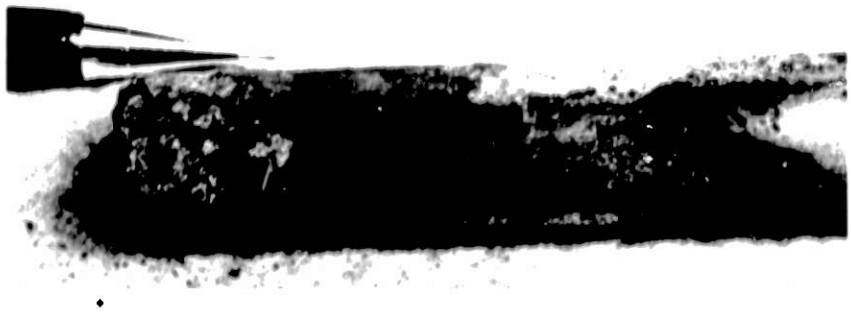
During the next test, type 1 thermocouples were again used in Stage I and II. The thermocouples were immersed 1" and 2-1/2" in Stage I and II respectively. Coal was fed to Stage II with no char feed to Stage I. Stage I temperature was held at 2300°F+ for approximately 24 hours during the test. All thermocouples provided accurate readings throughout the test.



PHOTOGRAPH NO. 1: Stage I SiC Thermocouples after Refractory Curing Operation. 10 days 2200-2800°F

TR 3401 - 5

PHOTOGRAPH NO. 2: Failed SiC No. 5 Stage II Outer Well. Coal Feed Test.



PHOTOGRAPH NO. 3: Failed Stage I Thermocouple. Failed after 30 hrs. Coal-Char Feed Test

Inspection of the outer wells indicated that No. 12 outer well was slightly eroded. No. 11 had been shortened approximately 1" and No. 10 had small silica globules on its tip. No. 2, 5 (Photo 2) and 6 Stage II outer wells had completely lost their exposed SiC and No. 3 was only slightly eroded. The molybdenum sheath on all thermocouples was in good condition.

COAL FEED/CHAR FEED TEST

During the next gasifier test both coal and char were fed to the gasifier with Stage I operating at 2500-2600°F and Stage II at 1500-1700°F. All thermocouples were immersed to 6".

After 28 hrs. and 30 hrs. of operation, Stage I thermocouples 11 and 12 failed respectively, probably reflecting the effect of char feed. Thermocouple 10 continued to give good readings throughout the 34 hour test. Post test inspection of the thermocouples revealed that the SiC and moly sheath had been completely removed to flush with the refractory wall, (Photograph No. 3). No. 10 thermocouples SiC was undamaged but had a hole in the center of the SiC.

Stage II thermocouples provided good readings throughout the test with maximum operating temperatures up to 1750°F. Thermocouples No. 2, 3, and 5 were in good condition; however, the SiC had been completely removed from No. 6.

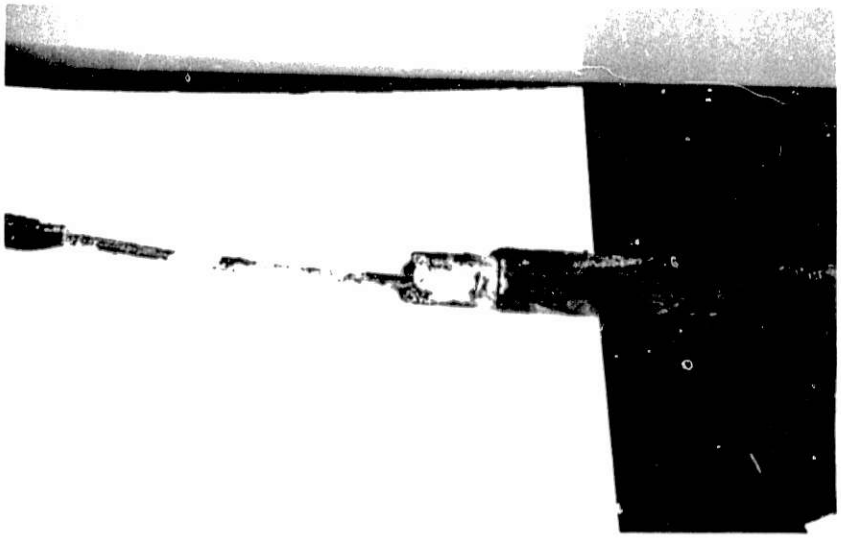
SECOND COAL-CHAR FEED TEST

In the second coal-char feed test, alumina hot section thermocouples as shown in Fig. 4 were installed in Stage I, and SiC hot section thermocouples in Stage II. All three Stage I thermocouples failed after fifty hours of operation. However, during this run, a gasifier upset occurred which may have caused their premature failure.

All Stage II thermocouples provided good readings throughout the test. The post test inspection of Stage II thermocouples, indicated that the SiC had been partially to completely removed on all thermocouples and the exposed molybdenum sheaths were slightly warped, but otherwise undamaged. (Photograph No. 4). One theory as to the failure of the Stage II thermowell was that the thermal or hydroscopic expansion forces of the annular insulation caused the failure of the SiC outer well. To eliminate the possibility of this occurring again, all other thermocouples were purchased without the annular packing.

THIRD AND FOURTH COAL-CHAR FEED TEST

Based on the good results with another design of SiC hot section thermocouple at the Westinghouse Low Btu Plant, Reference 8, a type 2 thermocouple was installed in Stage II. This thermocouple shown in figure 5 was basically the same construction as type 1 thermocouple except it utilized larger wires and inner sheath, a one piece sheath, with no annular packing. The type 2 SiC thermocouple performed better than the type 1. No. 11 lasted 73 hours before failure and No. 10 and 12 provided good readings throughout both tests. However, inplace inspection of the SiC wells indicated that the SiC had also been partially removed down to the moly sheath sometime prior to 60 hours of operation. The additional life of the type 2 over the type 1 can probably be attributed to its larger sheath and wire size. Subsequent runs have indicated that the life expectancy of the type 2 thermocouple is greater than the type 1 thermocouple.



PHOTOGRAPH NO. 4: Failed Stage II SiC Outer Well
Molybdenum Sheath Undamaged

PHOTOGRAPH NO. 5: Stage II 310 s.s. outer well sheath after 100 hrs. of operation

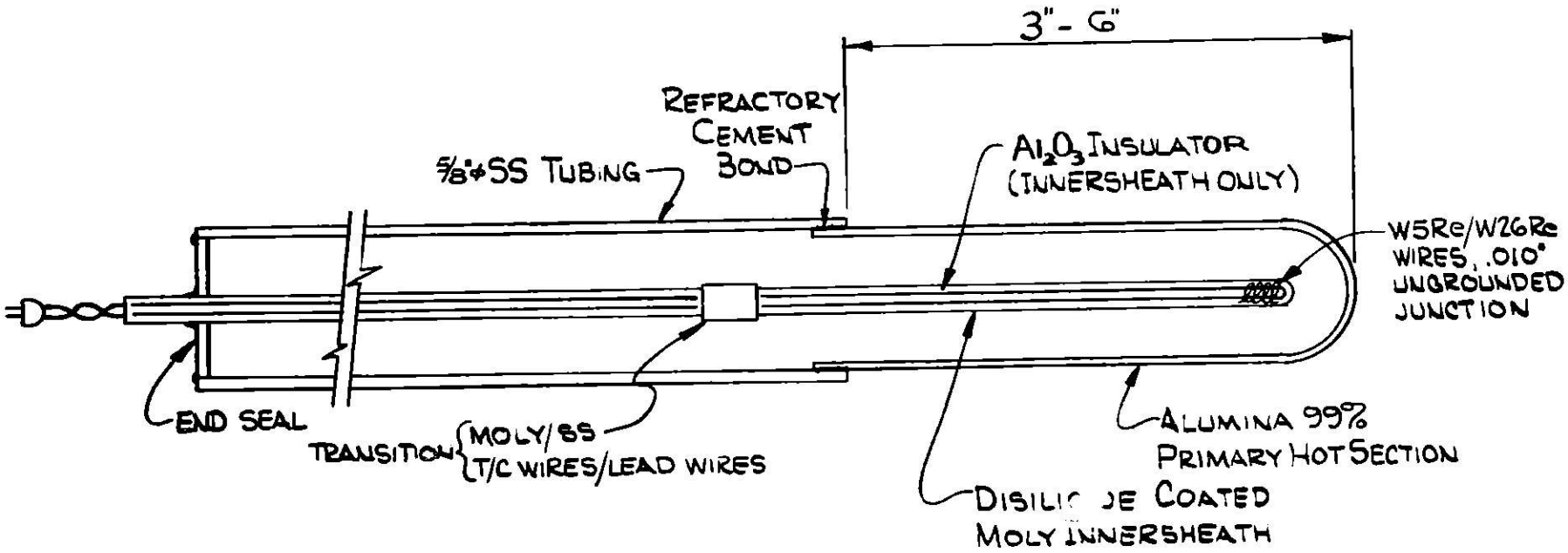


Fig. 4. Alumina Thermocouple

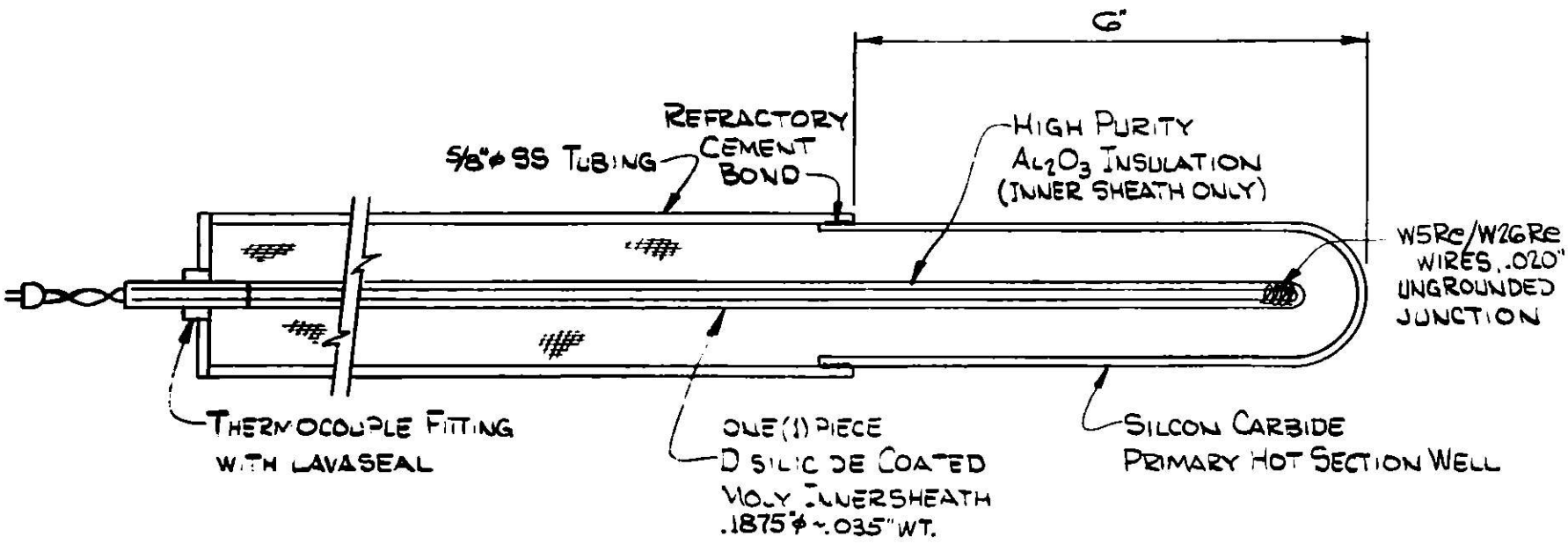


Fig. 5. Type 2 SIC Thermocouple

In Stage II, 310 s.s. outer wells were fabricated and 310 s.s. sheaths with type K wires were inserted. (Figure 6). The 310 s.s. was selected for the outer well because it is readily available, its melting temperature is above 2000°F, and it has good resistance to high temperature corrison, oxidation, and sulfur attack. To date these thermocouples have been installed approximately 150 hours with no failures or signs of outer well degradation. Photograph No. 5 shows the condition of a Stage II outer well after approximately 100 hours of operation.

SUBSEQUENT TESTS

In subsequent gasifier tests the Stage I thermocouples demonstrated similar type of failure patterns — initial failure of the SiC outer well followed by partial or complete loss of the moly sheath. Based on refractory tests conducted in Reference 1 and comparison of BI-GAS slagging and non-slagging tests, it appears that the failure of the SiC is greatly accelerated if its surface is wetted by slag.

CONCLUSIONS

310 s.s. thermowells have performed without failure in the BI-GAS Stage II environment. Current plans are to also evaluate 310 s.s. Alonized, 446 s.s., and Alonized Incoloy 800 in Stage II.

The molybdenum tube/tungsten-rhenium wire inner sheath combination appears to be holding up well considering the rapid loss of its protective outer tube and no changes in the inner sheath combination are being considered at this time.

SiC thermowells have experienced a high failure rate in the Stage I environment. Based on information contained in published reports and independent failure analysis, it appears that SiC will not withstand the high temperatures, slagging conditions of Stage I and alternate outer well materials must be evaluated.

Information presented in reference 1 through 4 indicates that high purity alumina and chromium oxide materials may be capable of withstanding the Stage I environment, and these materials will be tested at BI-GAS in the near future. In addition to these materials, literature searches and discussions with material vendors indicate that outer wells fabricated from molybdenum, ceramic coated molybdenum, and a molybdenum-zirconium oxide composite , also show promise in the Stage I environment.

Future gasifier operations will evaluate all of the above materials in an effort to obtain a satisfactory BI-GAS Stage I outer well.

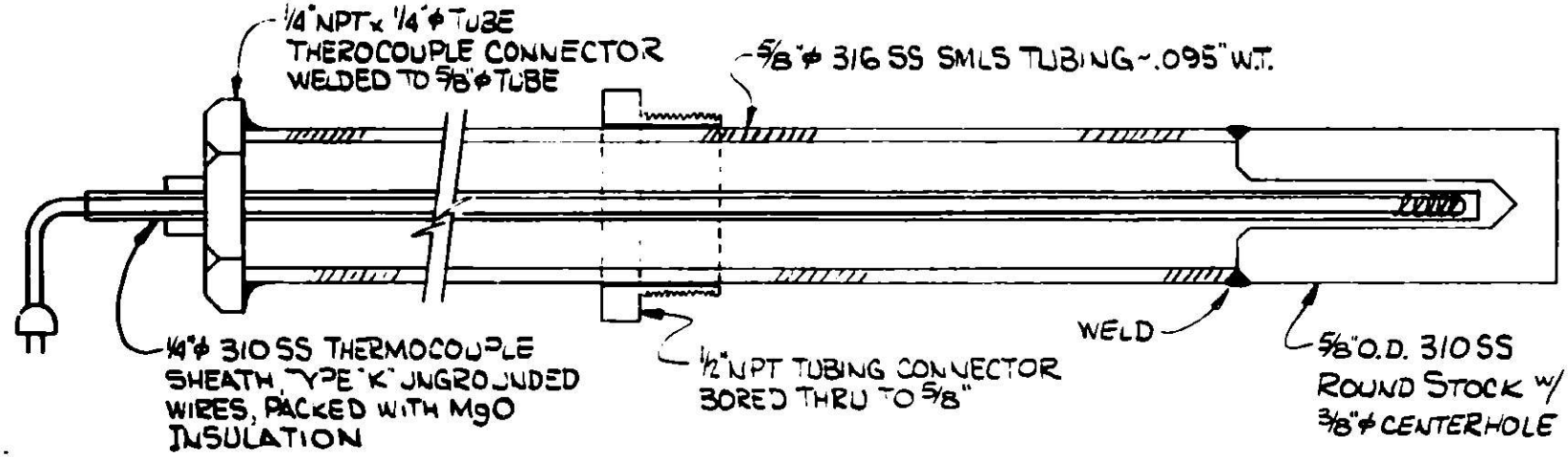


Fig. 6. BI-GAS "Homemade" 310 SS Thermowell

REFERENCES

1. Ceramic Coatings for Components Exposed to Coal-Gas Environments, R. Swaroop, Argonne National Laboratory Report ANL-76-124.

2. Failure Analysis of BI-GAS Thermocouples, C. R. Venable, Phillips Petroleum Company, Report VEN-29R-76.

3. Coal Technology July-September 1976 Quarterly Report, Evaluation of Ceramic Refractories for Slagging Gasifiers, D. Stahl, Argonne National Laboratory Report ANL-76-125.

4. Coal Technology October-December 1976 Quarterly Report, Evaluation of Ceramic Refractories for Slagging Gasifiers, C. R. Kennedy and R. B. Poeppel, Argonne National Laboratory Report ANL-77-5.

5. Telephone Conversation N. Pitcher (Stearns-Roger)/C. Kennedy (Argonne), June 22, 1977.

6. Evaluation of the Effect of Thermocouples Probe Immersion Length on Recorded Temperature in the BI-Gas Gasifier Vessel, N. D. Pitcher, Stearns-Roger Report No. 76-283.

7. Telephone Conversation, N. Pitcher (Stearns-Roger)/B. Johnson (E.R.D.A., Grand Forks, N.D.), June 30, 1977

8. Conference Report, Stearns-Roger (BI-GAS)/Westinghouse (Low Btu Gasification), January 31, 1977, Discussion of High Temperature Thermocouples.

QUESTIONS AND ANSWERS

N. D. Pitcher

Stearns-Roger Incorporated

J. Modla, Buel-Envirotech

Q. What is considered as "high accuracy" in temperature measurements since only mean temperatures are being measured?

A. We are not really concerned with high accuracy. I believe standard thermocouple accuracy is 1/2% in the 1000°F range. If we get a 50° accuracy at our 3000° operating temperature, we'd be happy.

Q. What is the response time of the thermocouple?

A. I don't know, and I'm not really all that concerned about it at this stage of our thermocouple development. Once again, we are just trying to get some type of good reliability. I believe an ISA transaction did give response times for protected well thermocouples, and I will try to locate that paper. ("Thermal Response Time of Sheathed Mineral-Insulated Thermocouples", A. Thomson, Transactions of the Society of Instrument Technology, June 1965.)

W. H. Fischer, Gilbert Associates

Q. How were the ceramic and stainless steel and seals made?

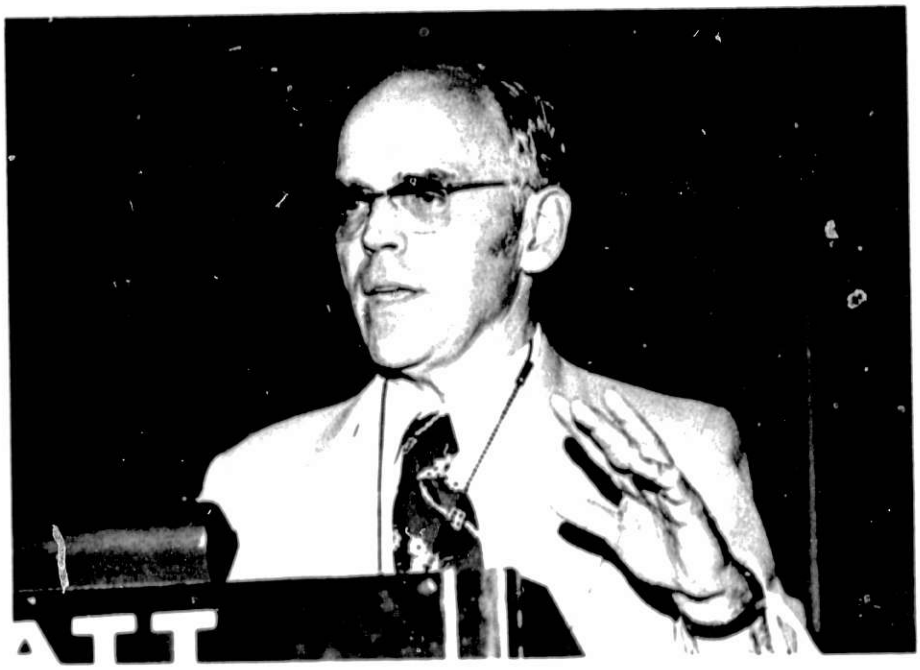
A. With the "home-made" type, the thermocouple sheath/stainless tubing seal is made with a conax lava seal. Those thermocuoples we purchase from vendors use a welded type junction. The joint between the ceramic protection tube and the 5/8 in. ∅ stainless tube was made using a high temperature refractory cement. (Sauereisen Cement Co., No. 78 cement.)

G. H. Quentin, Electric Power Research Institute

Q. How do you compensate for thermal losses from your thermocouples due to radiation? (That is, thermal radiation to colder surfaces.)

A. We don't. That heat transfer study which I referred to in my paper did not consider radiation. It considered conduction and induction effects. Babcock and Wilcox's book "Steam" indicates that radiation effects can cause errors up to 200°F at 3000°F operating temperatures in conventional wall tube boilers. However, since the BI-GAS walls are refractory lined and continuously wetted with flowing slag, radiation errors should be minimal. The best method to avoid these radiation errors if they were significant would be to utilize a high velocity thermocouple.

INFRARED RADIOMETRY APPLIED TO CRITICAL TEMPERATURE MEASUREMENT IN THE COAL GASIFICATION PROCESS



R. F. Leftwich
Barnes Engineering Company
Stamford, Connecticut

INFRARED RADIOMETRY APPLIED TO CRITICAL TEMPERATURE MEASUREMENT IN THE COAL GASIFICATION PROCESS

Richard F. Leftwich
Barnes Engineering Company

I. INTRODUCTION

Infrared Radiometry can be used to both monitor the temperature and spectrally scan the radiation inside a coal gasification reactor. The high temperatures are best monitored by optical infrared means and the spectral scanning is used for evaluating the coal gasification process. Equipment is now under design and construction for installation 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.

Coal dust is gasified in the upper section of a vertical reactor. After separating from the coal gas, the char is injected together with high pressure steam and oxygen into the lower section of the reactor. The peak process temperature is approximately 3200°F. It is this temperature which is of interest in the monitoring mode. A threshold level is used to provide a flameout alarm.

The purpose of the scanning mode is to provide the capability of monitoring the flame process. Under normal operative 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 abnormal reactions.

II. PHYSICAL ARRANGEMENT

The lower section of the reactor is shown in Figure 1. Char approaches the reaction zone at roughly 1800°F at the top, followed by 2700°F, and then 3200°F in the reaction zone. We can expect about a 3-foot layer of burning char. High pressure steam and oxygen are injected through the char burner nozzles. The char burning is initiated by a flow of triethylene aluminum (TEA) and oxygen in tubings mounted inside the char ignitor.

The slag formed during the coal and char gasification flows downward along the walls of the reactor and is collected by the slag tap. It is kept in molten state by the slag tap burner, and the slag tap is observed by a TV and an observation port. Slag temperature can be controlled by controlling oxygen flow. The char ignitor, as shown in Figure 2, has three purposes: (1) to initiate the char burning, (2) to allow flame detection by a radiation detector, and (3) to allow temperature monitoring of the char burning area. The char ignitor is essentially a pipe nine (9) feet long with a 1.69 inch inside diameter. The tubes for TEA and oxygen are also shown, partially blocking the optical path. Inside the pipe, methane gas is presently used to purge a clear optical path. The methane purge gas is used to reduce the flow of char particles up the pipe. This has the secondary effect of limiting the portion of the optical path subject to intereference by gases such as oxygen and carbon dioxide. Nitrogen can be substituted for the methane if necessary.

Figure 3 shows the arrangement of the sensors as mounted on the sighting ignitor tube. Ambient temperature range is 20-110^{o}F. A NEMA-4 enclosure is required for the explosive environment Class I, Division 2, Group D. The necessity of transmitting the infrared radiation requires the use of an infrared window which does not conform with regulations for this classification. In order to make the system intrinsically safe, the enclosure will be continuously flushed with dry nitrogen and will have a self-contained window independent of the sighting tube window to prevent any interaction. A reflector and beam splitter arrangement is provided to allow both sensors to use the same sighting tube.

III. OPTICAL SENSORS

The beam divider is shown in Figure 4. The spectral scanner uses the 1-inch straight through lens, and the beam is divided by the beam splitter and also sent to the temperature monitor radiometer. The size and focal length of the lens is determined by the dimensions of the sighting tube. A dichroic beam splitter is shown, that is to say, nearly all radiation shorter than a certain wavelength will be reflected, and all longer radiation will be transmitted. This avoids the attenuation of the conventional partially reflecting beam splitter. The cut-off wavelength must depend on the operating wavelengths of the two instruments. If the temperature monitor wavelengths turn out to overlap the scanner wavelength range, then a conventional beam splitter can be used.

Temperature Monitor

The temperature monitor is shown in Figure 5 in the form of a Model 12-880 Precision Radiometer. This is a modular unit that includes manual 4-position filter wheels for selecting different operating wavelengths. The optical head is 6-inches diameter by 7-inches long and weighs 4 pounds. Signals from the optical head are sent to an electronics unit as much as 300 feet distant for amplification and demodulation. The electronics will have a 4-20 milliamp dc output, and contains a single set point controller for use as a threshold flame out alarm. The response time is of the order of 50 milliseconds.

The optical head contains a lens, filter wheel, and detector in a temperature controlled cavity for high stability. The incoming beam is optically modulated by a reflective chopper at approximately 100 Hz. When the chopper is closed, the detector sees the temperature controlled reference cavity reflected in the chopper. A phase reference pickup senses the chopper position for synchronous demodulation of the signal. For this application, a photoconductive lead sulphide detector, sensitive in the visible to 2.5 micron region, will be used together with a lens to give a nominal 10 milliradian field-of-view.

Spectral Scanner

A photo of the SpectralMaster Infrared Radiometer with its electronics unit is shown in Figure 6. The optical head is 5.5 inches diameter by 20.5 inches long and weighs 15 pounds. The optical schematic is shown in Figure 7. For this application, the primary and secondary mirrors will be removed and replaced by the 1-inch lens shown in Figure 4 which has the same f/number. The head uses modular, optical shelf type construction and will accept a variety of optics, filter assemblies, and detector modules. A pyroelectric thermal detector is used here which is equally sensitive to all wavelengths. Still it has the high, fast response required for spectral scanning. The detector requires no cryogenic cooling typical of long wave photo detectors, thus simplifying operation in this environment.

The electronic block diagram is shown in Figure 8. It includes, attenuators, amplifiers, and synchronous demodulators for the signal. There are also controllers for the chopper and the cavity temperature. Finally, spectral scanning is accomplished with a Circular Variable Filter, described next, whose effective transmission wavelength is proportional to shaft position.

Therefore, a binary shaft encoder and processing is provided to accurately read-out the filter shaft position.

Circular Variable Filter

As shown in Figure 7, the motor driven Circular Variable Filter (CVF), used for spectral scanning, is located in the second focal plane. The principles of operation of the CVF are shown in Diagram A. An interference filter is made up of a multiplicity of 1/4 wave and 1/2 wave thin film layers designed for the wavelength of interest. Multiple internal reflections take place within these films thus producing destructive or reinforcing interference depending on the phase of the wavelength in question. The transmitted wavelengths are determined by the index of refraction and thickness of the thin evaporated layers. If the filter is constructed in the form of a circular wedge as shown in Diagram B, then wavelength will be proportional to angle, that is, shaft position. The filter is constructed with one octave of wavelength change in 180 degrees. A given filter segment is limited to one octave of wavelength because the nature of the intereference effect repeats with harmonics of the design transmission wavelength. To prevent the transmission of harmonics, the segment includes an intrinsic blocking material which limits transmission to the desired octave. For the reactor application the initial filter will cover 1.6 to 3.0 microns nominal in one segment and 2.9 to 5.6 microns nominal in the other. This covers the large portion of wavelengths of interest at the reactor process temperature.

The need for locating the CVF at a focal plane is explained in Figure 9C. Since the CVF is continuous, a narrow slit must be placed in front of it to limit the range of wavelengths transmitted at any given instant. Similarly, radiation coming in at different angles from the collecting aperture will tend to widen this wavelength spread. Therefore, this angular spread must be kept to a minimum consistent with adequate collecting power.

IV. WAVELENGTH CONSIDERATIONS

The target in the reaction zone of the Coal Gasification Reactor as shown in Figure 1 is flame and solid material resulting from the burning of approximately 70% of 200 mesh solid carbonaceous material mixed with 1200 psig steam and oxygen. The background is molten slag flowing down along the reactor walls. The flame should exhibit emission bands including CO_2 and water vapor. It is reasonable to assume that the radiation from the char burning

itself is blackbody in nature.

Spectral emission from a typical 1000°C blackbody is shown in Figure 10. A blackbody at 3200°F (1760°C) will move the peak up and shorter to approximately 1.4 microns. Of course, measurement of the radiation at any wavelength will identify the curve, and thus the temperature, as long as black body conditions exist at that wavelength.

Figure 11 shows the transmission spectra of CO_2 and H_2O. If we wish to measure the temperature of the burning char, we might choose 2.1 microns or something shorter than 1.7 microns in regions where the flame should be transparent. On the other hand, the flame temperature itself can be measured in the region between 1.8 and 1.9 microns.

Figure 12 shows the spectral transmission of methane. This has annoying absorption structure extending from 3.15 to 3.5 microns. Methane should not disturb the temperature monitoring, but it appears that the methane will have to be replaced by nitrogen to permit proper spectral scanning. Nitrogen is completely spectrally transparent.

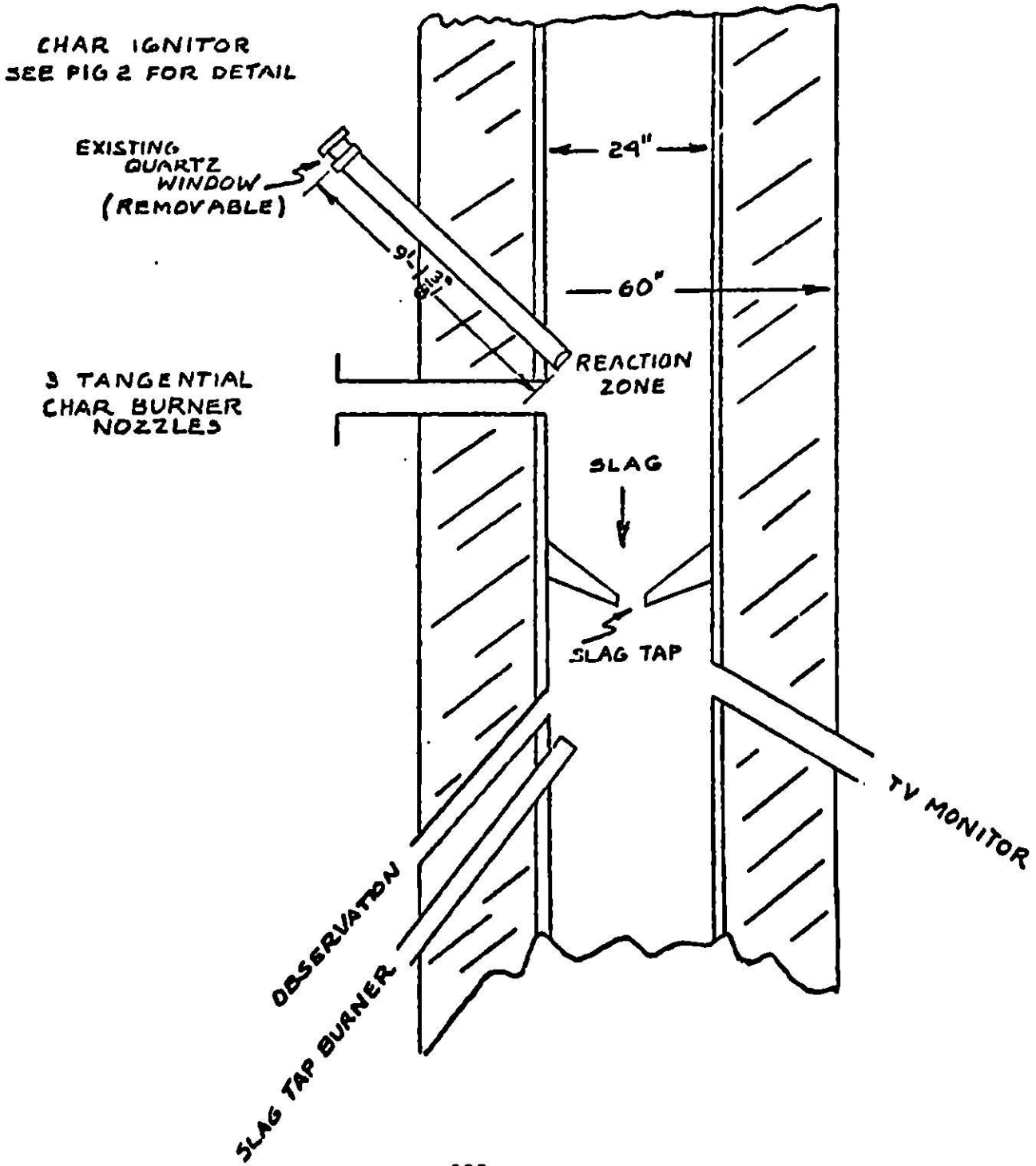
Figure 13 shows typical oscilloscope displays of the 12-550 SpectralMaster scans. For transmission studies, the radiometer looks at a hot continuous source such as a blackbody radiator through an atmosphere of the gas in question. When the gas itself is hot enough such as in a flame, the emission spectra can be displayed. The spectral resolution achieved in these scans is 2 to 3% of the wavelength being measured, which is quite adequate for the Reactor application. Instrument noise should also not be a problem. Calculations for the spectral scanner as described with a pyroelectric detector and 55 Hz electrical bandwidth were made at the minimum operating temperatures of 2800°F. At the peak wavelength, the signal-to-noise ratio was better than 1000:1 dropping to 200:1 at 1.3 microns and 300:1 at 6 microns.

V. CONCLUSION

Two infrared radiometric instruments have been described for monitoring the radiant energy inside a coal gasification reactor. One supplies rapid temperature monitoring and the other provides spectral scanning to evaluate the process performance. Both instruments have adequate environmental, speed of response, and sensitivity capabilities. In addition, they

have modular flexibility to readily adjust the field of view, wavelength region of operation, and performance characteristics to accommodate necessary changes based on new information about the reactor as it becomes known.

FIGURE 1 - COAL GASIFICATION REACTOR



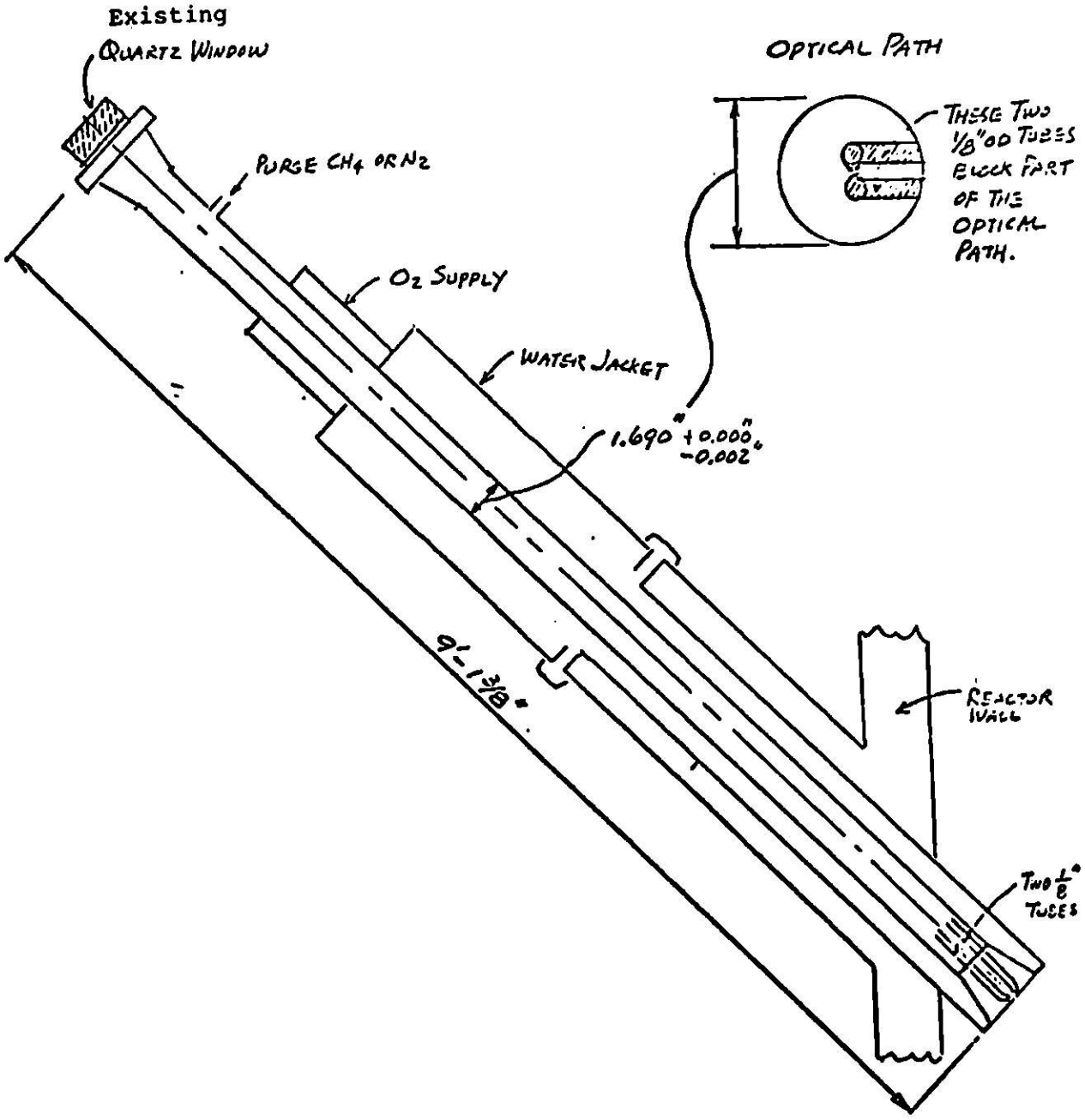


Fig. 2. Char Ignitor and Existing Sight Tube

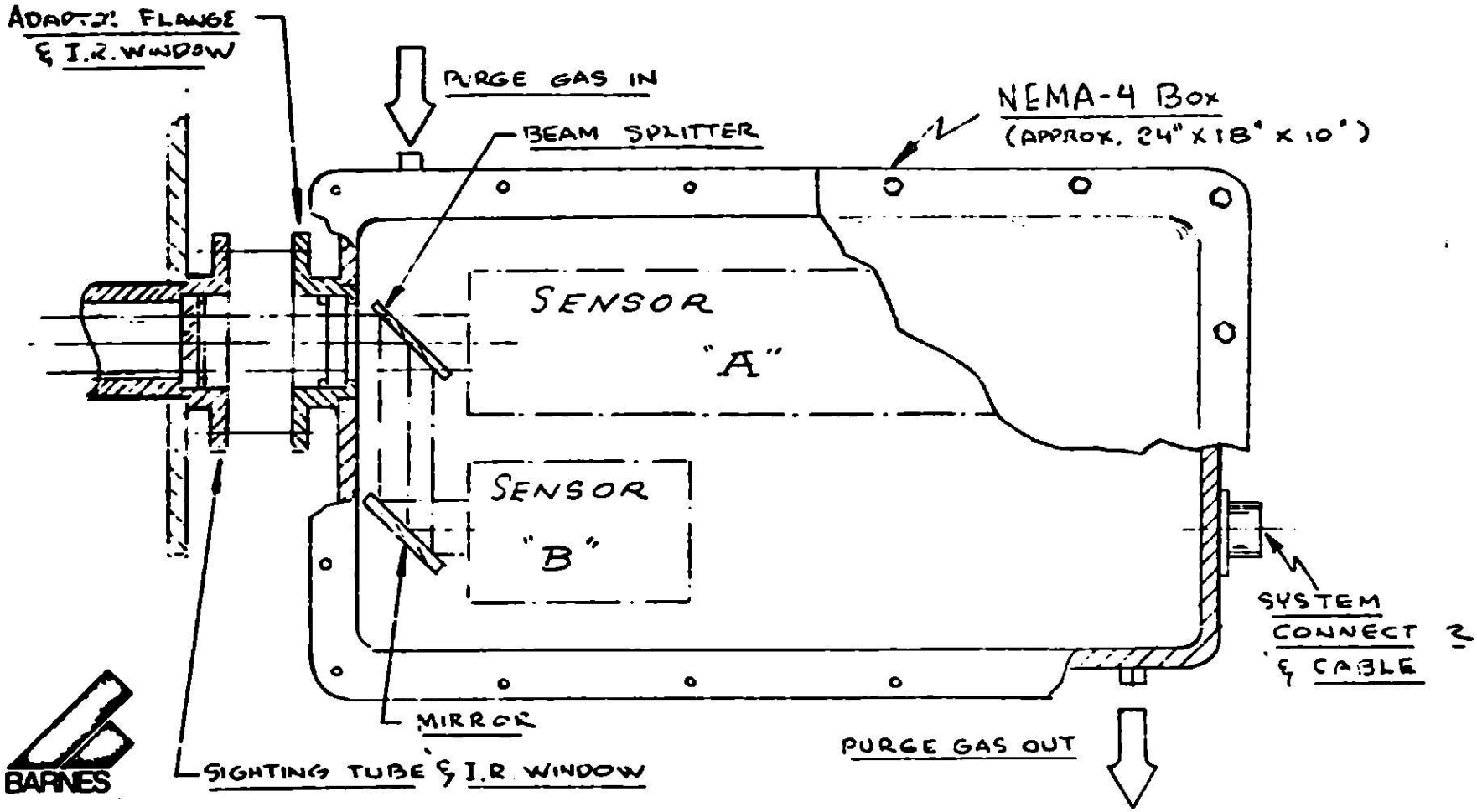


Fig. 3. Infrared System

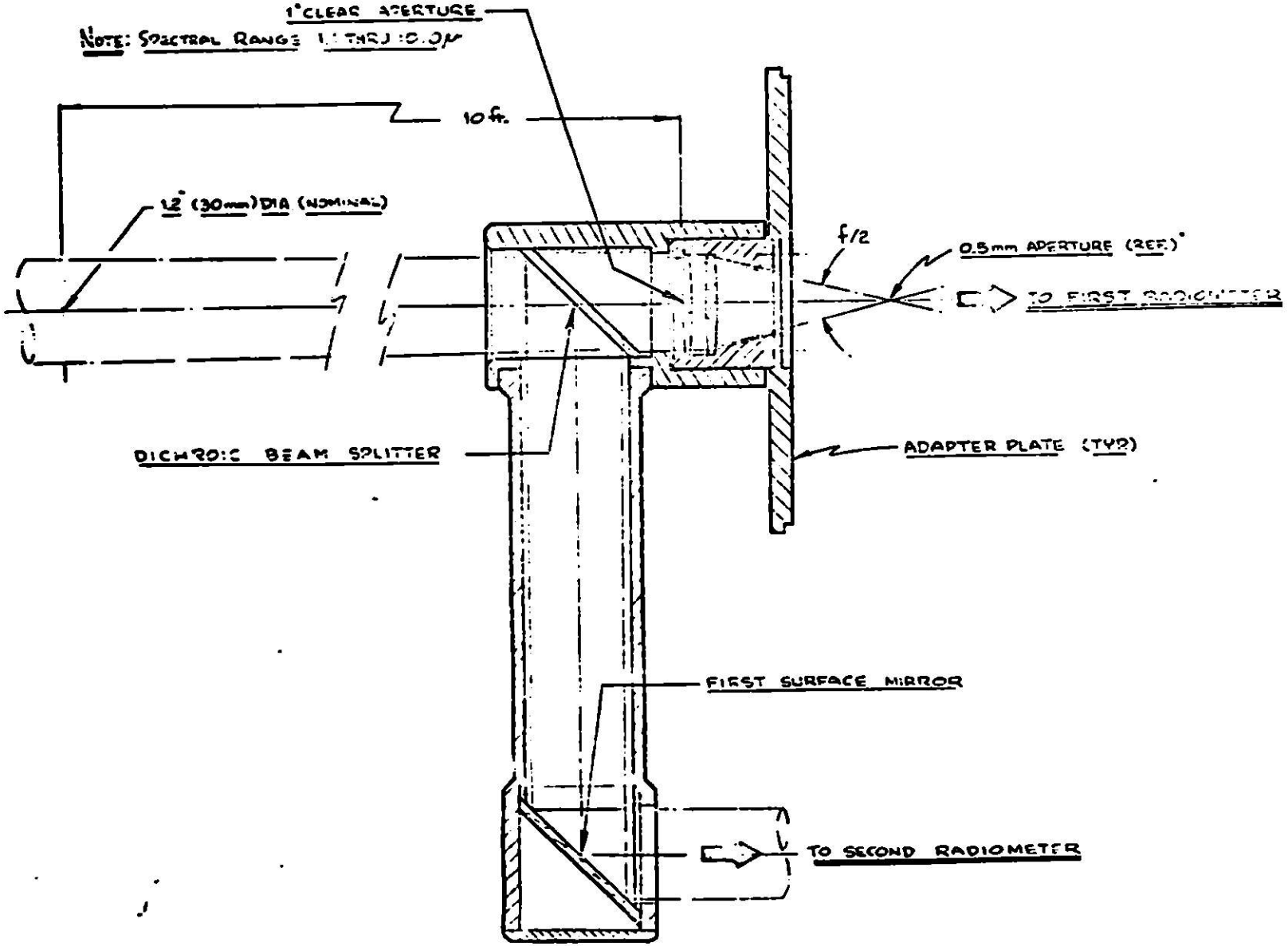


Fig. 4. Infrared Optical System

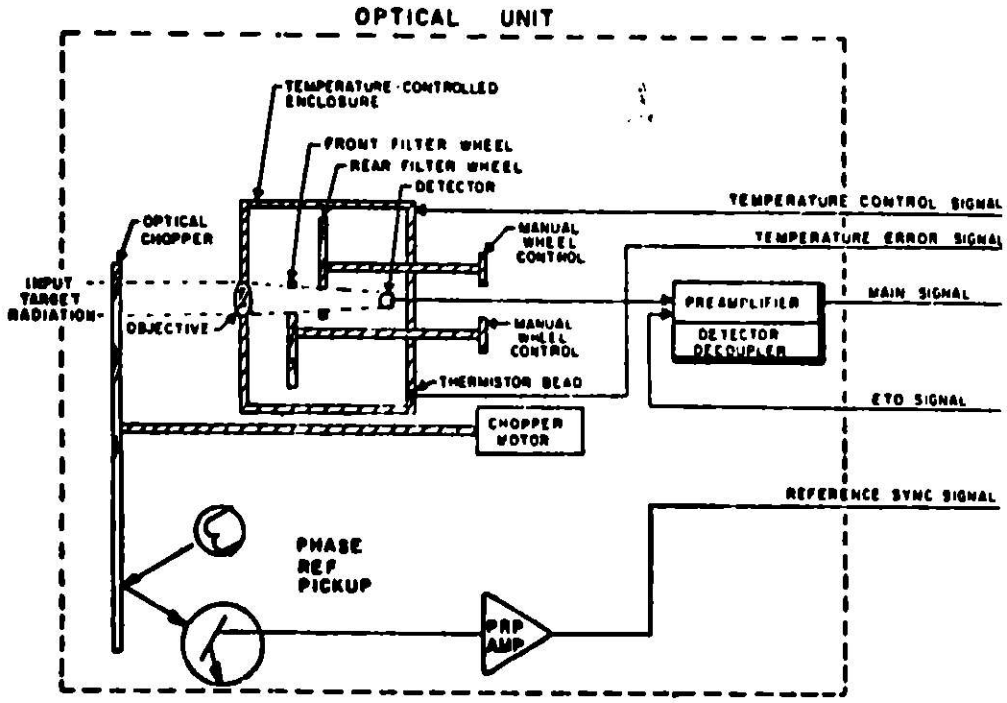


FIGURE 5. MODEL 12-880 PRECISION SPECTRO RADIOMETER OPTICAL UNIT

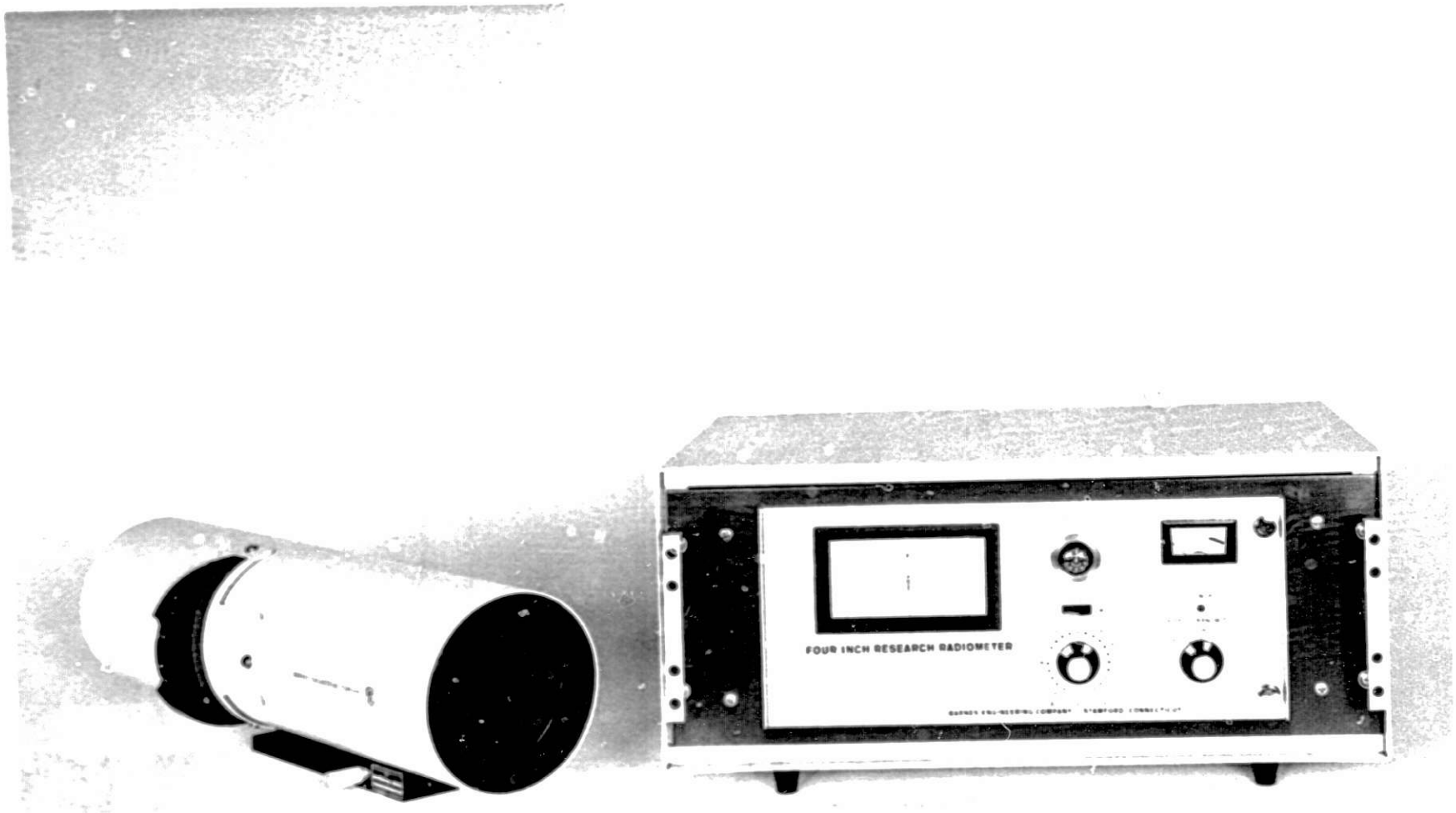


Fig. 6. Spectral Master Infrared Research Radiometer

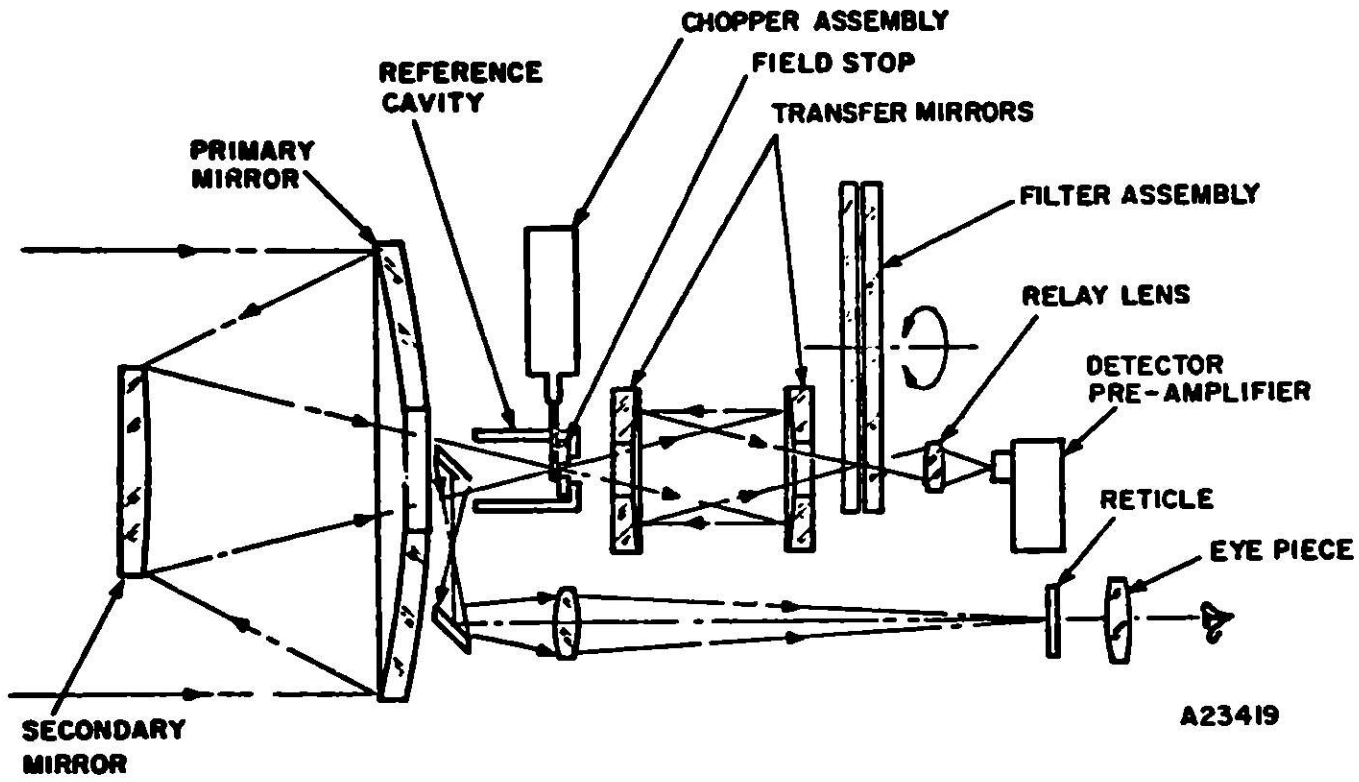


Figure 7. Optical schematic, SpectralMaster Model 12-550

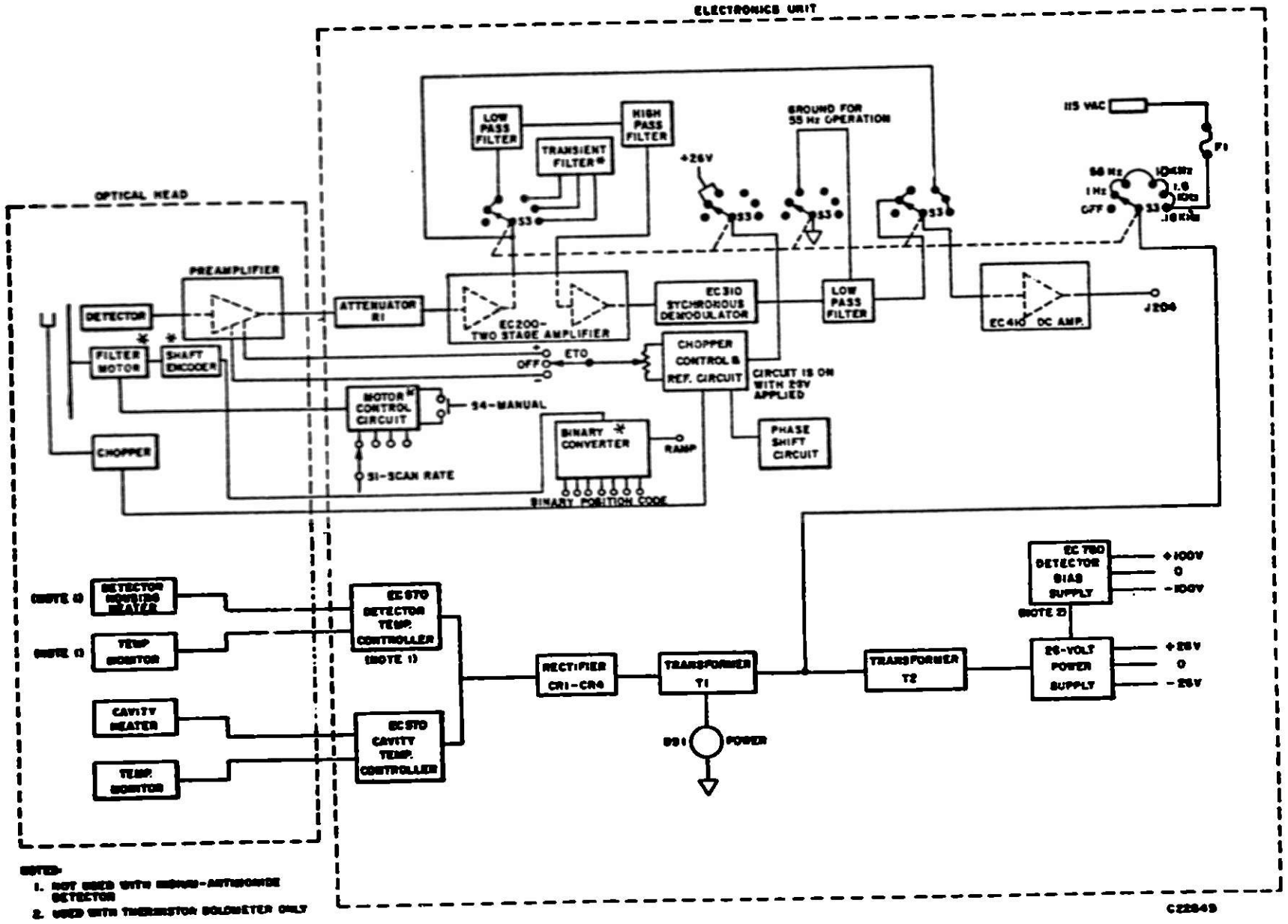
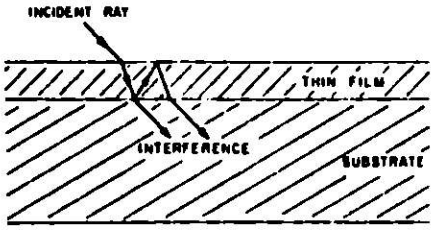
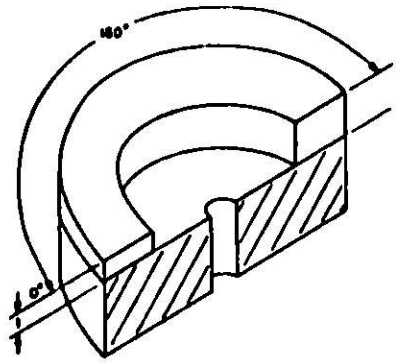


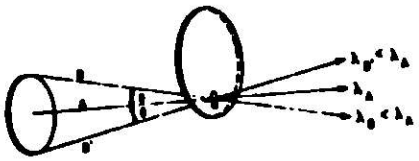
Figure 8. 12-550 Electronic System Functional Block Diagram



A.



B.



C.

FIGURE 9. Circular Variable Filter Diagrams

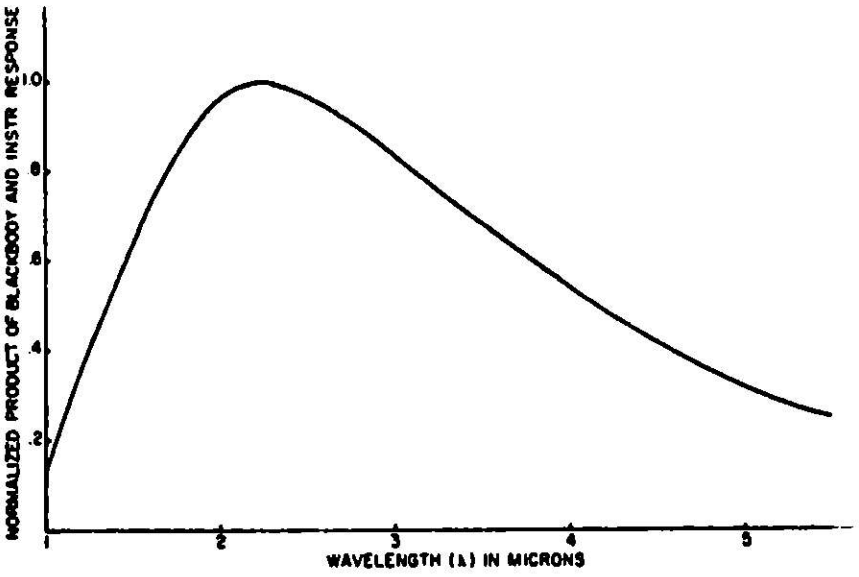


FIGURE 10. Spectral Curve of Blackbody at 1000°C

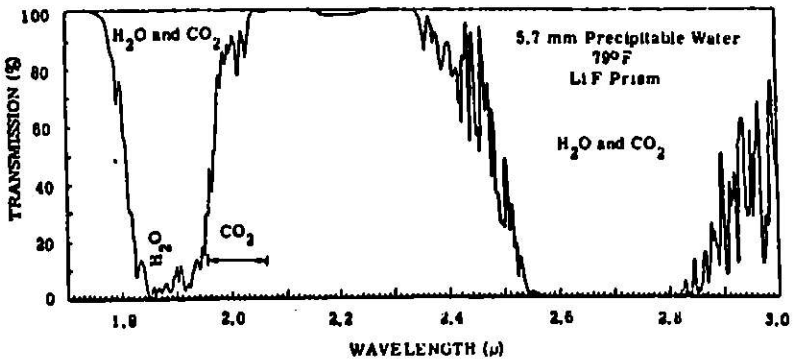


FIGURE 11. Spectral Transmission of CO_2 and H_2O

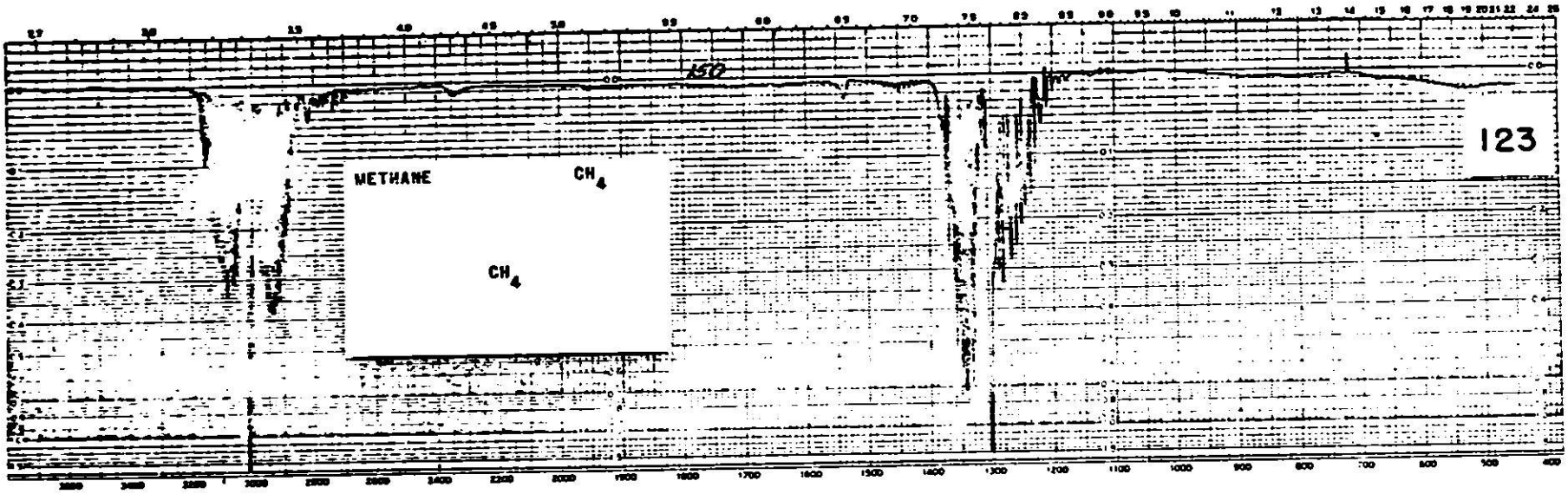


FIGURE 12. Spectral Transmission of Methane

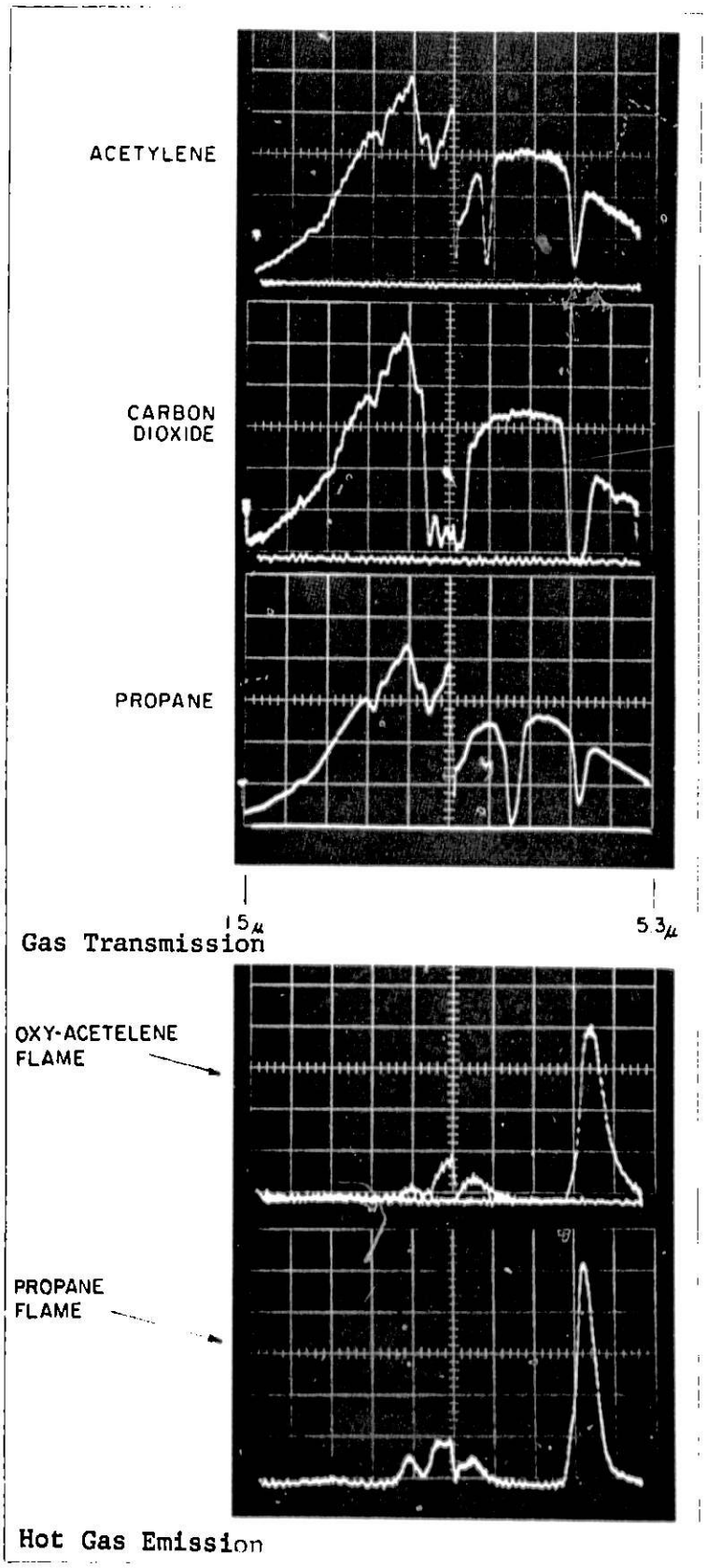


Fig. 13. Spectral Output of 12-550 Radiometer for Some Typical Gases

QUESTIONS AND ANSWERS

R. F. Leftwich

Barnes Engineering

J. J. Eichholz, Argonne National Laboratory

Q. I believe that a black body hole would not be necessary, i.e., emissitivity change would not be a problem, if a two color system were employed. Please elaborate on advantages or disadvantages of a single over a two color system.

A. That is very good, and happens to be a favorite topic of mine. Have you got another half hour? I'll tell you briefly. I think you saw from the black body curves that a single wave length describes the black body curve. If the emissitivity is less than unity, but constant everywhere, a ratio of any two points, would also give a unique answer, and that's what he's talking about. There is one assumption there that is critical, and that is that if you work at two wave lengths, the emissitivity will cancel out only if the emissitivity of those two wave lengths is equal. It doesn't have to be one, but it has to be equal. Now, experience shows that this is a very dangerous assumption, and there was paper by NBS on that subject, where they said that by and large, two color radiometers can lead to trouble. The trouble is that if you have a single color radiometer and you assume some emissitivity which turns out to be not quite correct, the error is small. If you have a two color radiometer and the assumption is wrong the error is immense, something like 500%. So that is the concern we have, although we probably will experiment with it some, with our filter wheel.

W. E. Shannon, Lockheed Palo Alto Research Laboratory

Q. Utilizing conditions of operation, assumptions on performance or other criteria for design as you may select, please provide an indication of price to acquire the device which you have just described?

A. We are talking roughly about $60,000 I would say. That doesn't necessarily include the infrared filters that may be added, and that does not include installation which would be done by the plant engineering people.

M. R. Cines, Phillips Petroleum Company

Q. There will be appreciable concentrations of H_2 and CO in STAGE I—will they cause any problems?

A. Who can guide me, STAGE I at the top or the bottom? The bottom. The answer is no. We of course will select for the temperature monitoring wave length regions where the CO and H_2 are transparent and for the spectral scanning, the H_2 and CO we are interested in. So I think the answer to that is no.

P. F. McCrea, The Foxboro Company

Q. Would you care to speculate on the likelihood of being able to determine bed level via spectral means, i.e., by viewing targets on the opposite wall using your fiber optic approach.

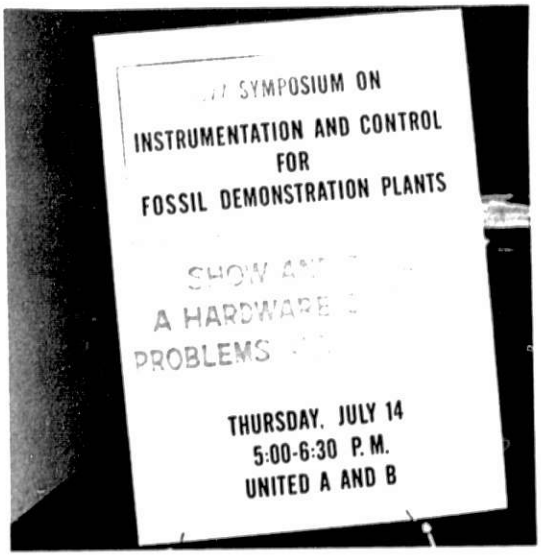
A. That is a possibility. The way you should do that, is to use an array of fibers or an array of detectors; these kinds of things are done and are called optical gauging. It can be done, it's just the details that I'm worried about. It's certainly something worth discussing.

John Modla, Buell-Enrivotech

Q. What type of coating is on the beam splitter? Is 50% of the radiation transmitted and 50% reflected? You mentioned in your abstract that "the spectral situation changes with time". Could you quantify this statement?

A. The beam splitter, if it's a dichroic beam splitter, 50% is not transmitted to 50% reflected. For instance, a very simple dichroic beam splitter is a piece of germanium. Now a piece of germanium reflects everything short of 1.8 microns, almost 100%, and if it has an anti-reflection coating on it, will transmit 95% of everything longer than 1.8 microns. It is also possible to make beam splitters by interference techniques, the same way you make filters, because an interference filter reflects whatever it does not transmit. If we wish to make a 50% transmitting non-dichroic beam splitter, we can do that by a thin coating of evaporated aluminum or a thin coating of one of the other metals that slips my mind at the moment; there are many of them.

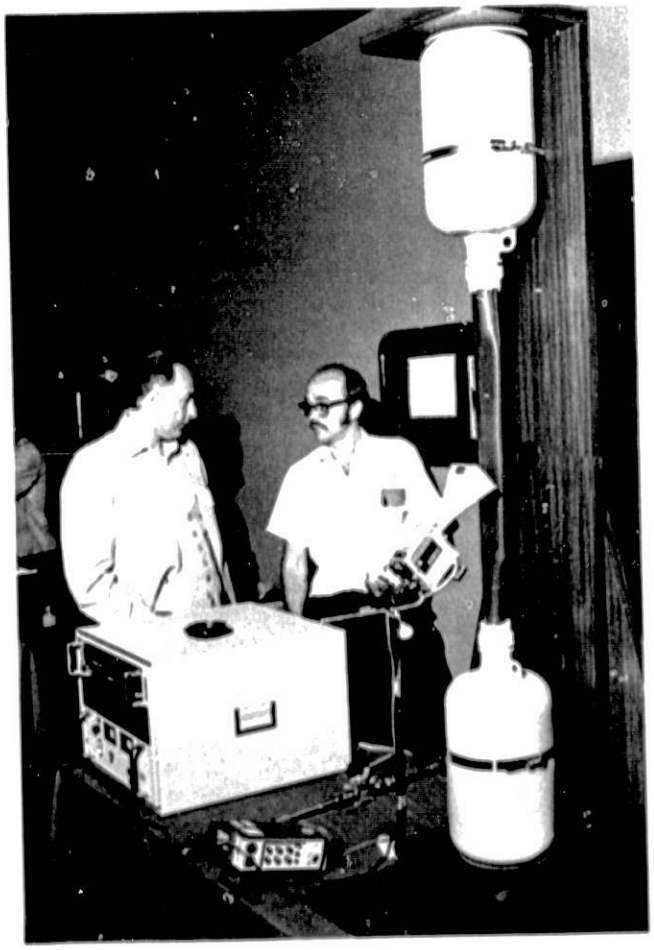
You mentioned in your abstract that the spectral situation changes with time. Well, I'm concerned that it changes with time, and that of course, is part of the process that we need to learn about. We haven't been on the process yet. The purpose of the spectrum scanner is to scan the spectral situation, and I said in the introduction, in case anything occurs that represents abnormal reaction. If everything is working just so, then perhaps the spectral situation will not change with time. But if something untoward occurs, then we will quickly note it; a rise in the presence of one gas and a reduction of another. I'm really going by what the process people here, such as John Walsh told me. Thank you John. We have enough flexibility we hope that when we go onto the process, and if we guessed wrong we can change a filter or something and still be in business.


SYMPOSIUM ON
INSTRUMENTATION AND CONTROL
FOR
FOSSIL DEMONSTRATION PLANTS
THURSDAY, JULY 14
5:00-6:30 P.M.
UNITED A AND B

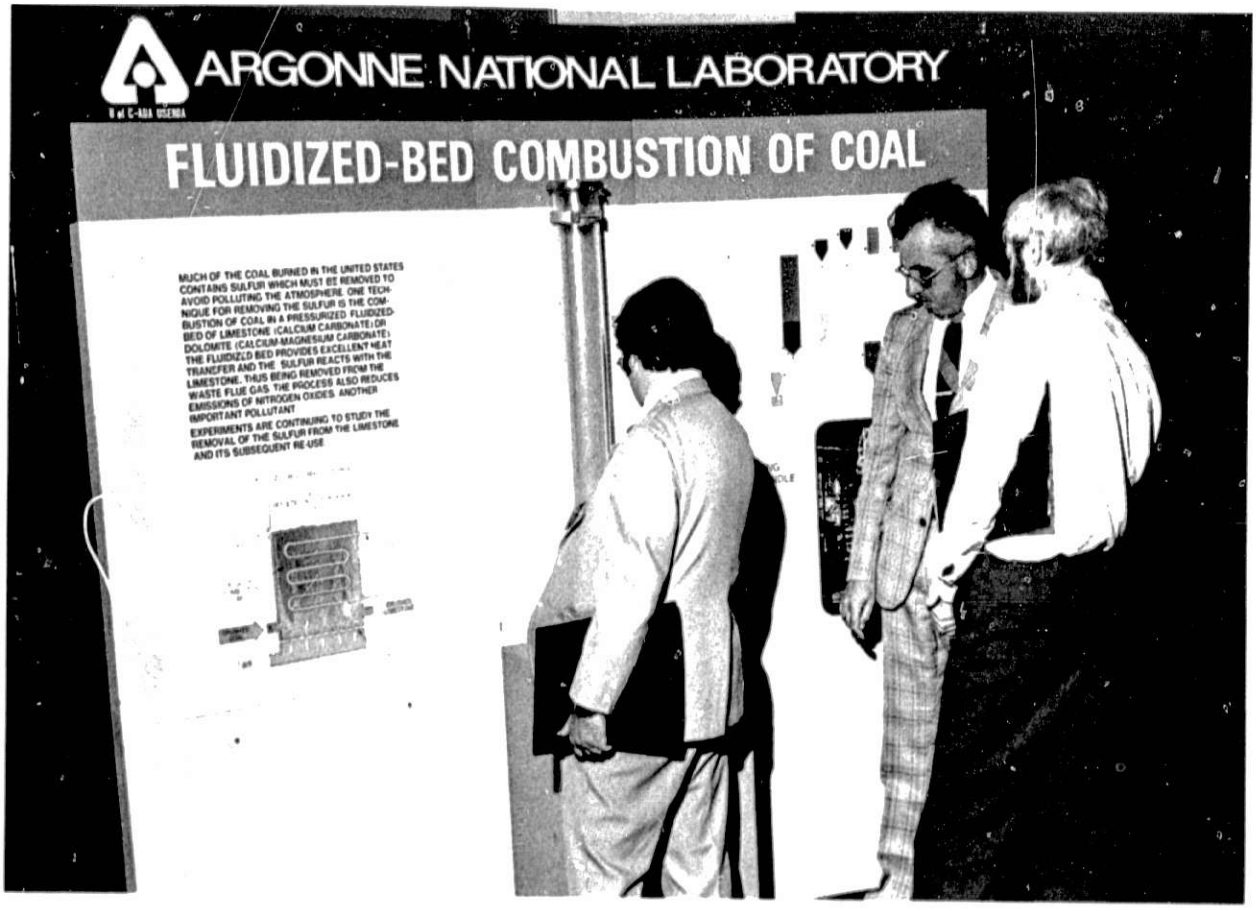
Synthane

BI-GAS

HYGAS

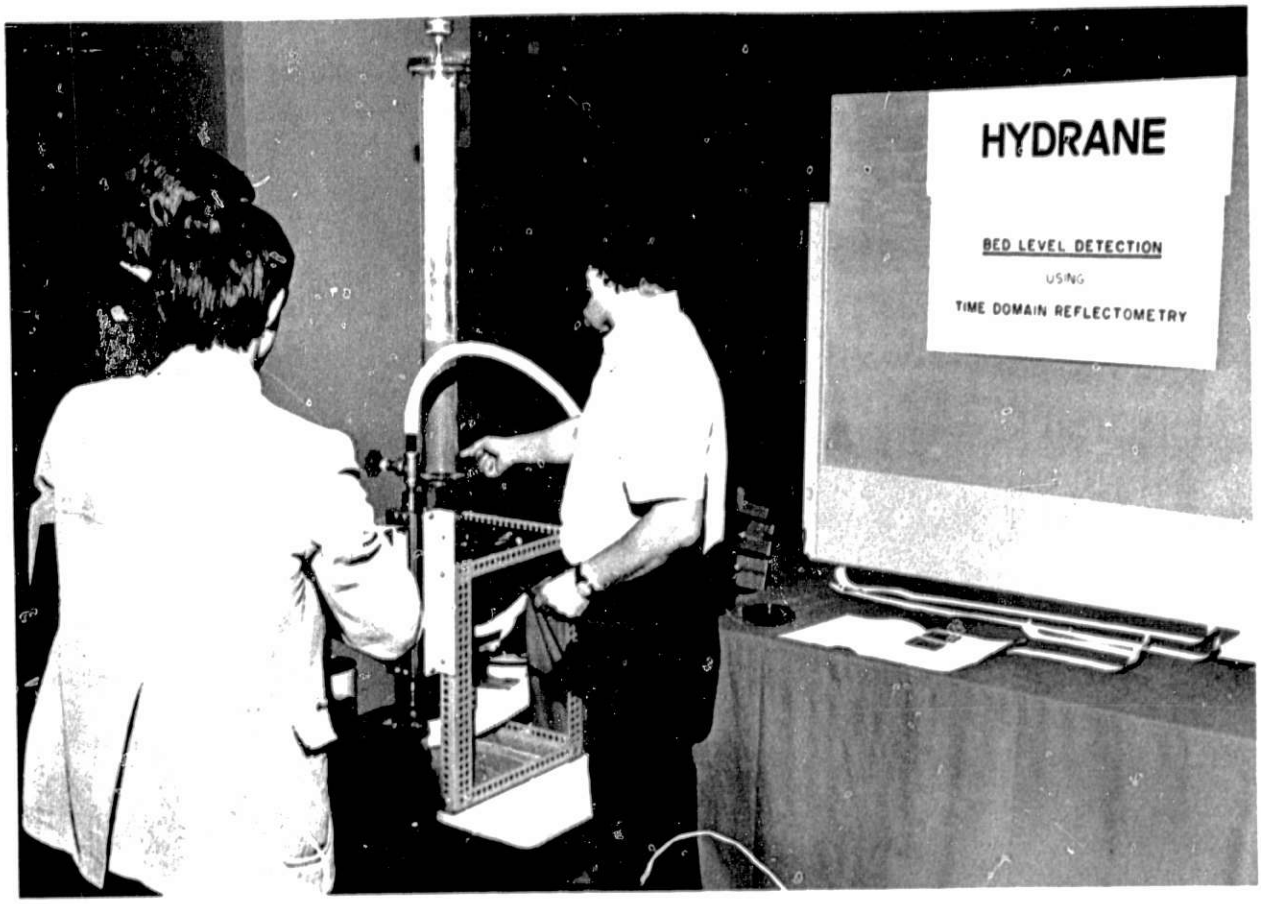


Westinghouse ESO

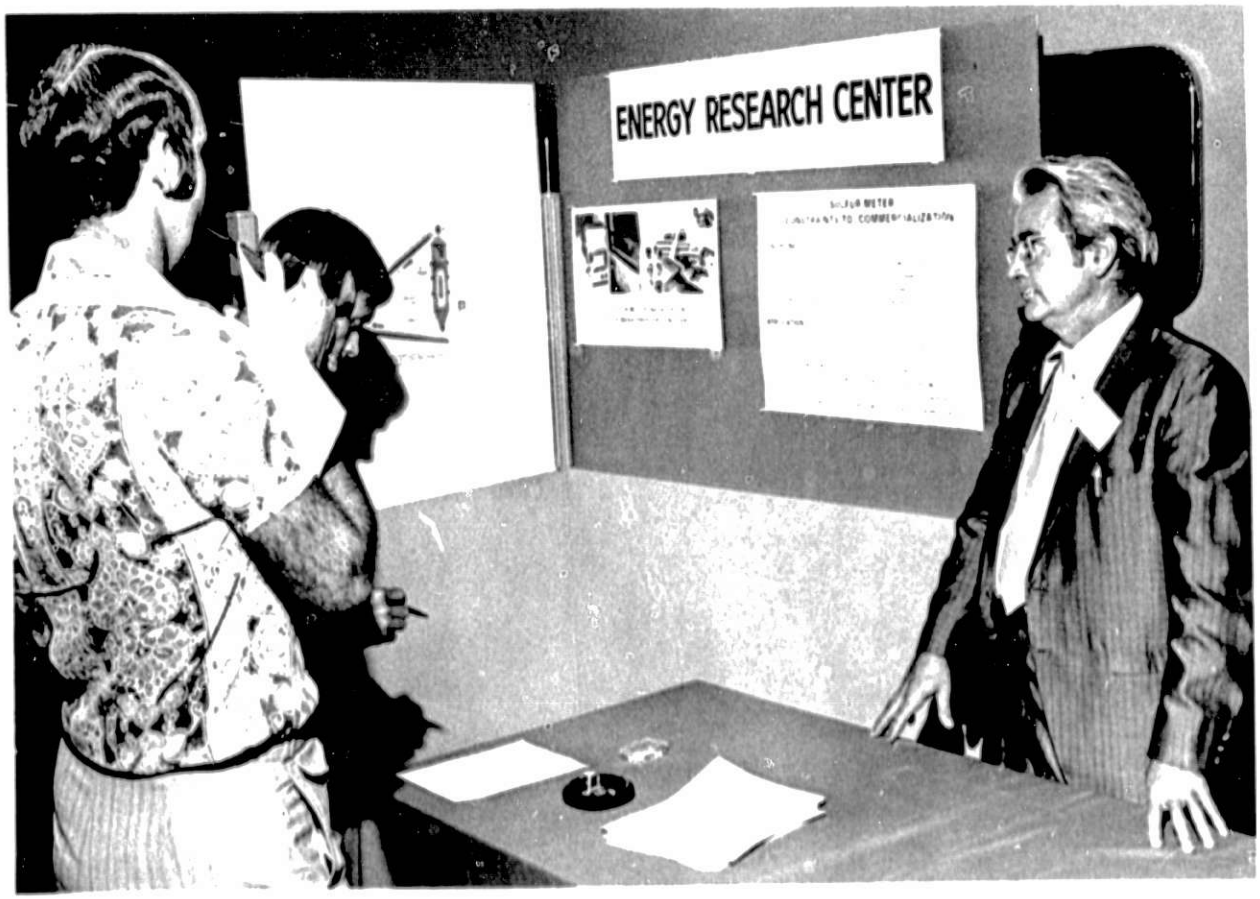


Argonne National Laboratory

Spectron Development Laboratories



Hydrane



Morgantown Energy Research Center

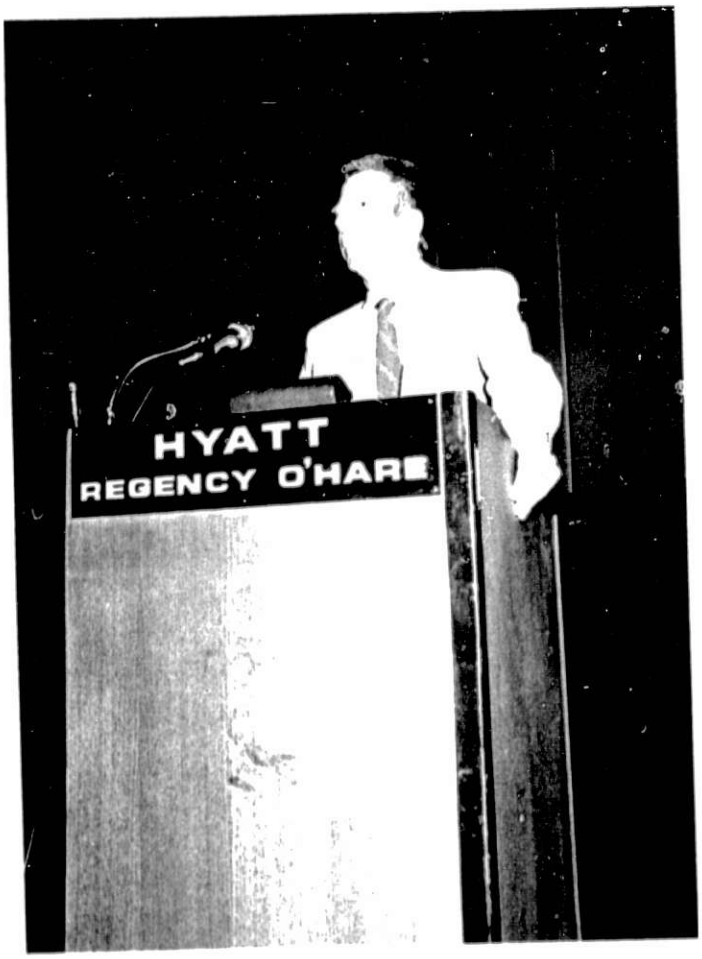
PROCESS CONTROL -- PANEL DISCUSSION

Session Chairperson

R. F. Detman

C. F. Braun and Company
Alhambra California

DISCUSSION PANEL MEMBER



W. E. Schiesser
Department of Chemical Engineering
Lehigh University
Bethlehem, Pennsylvania

DISCUSSION PANEL MEMBER

B. G. Lipták
Lipták Associates
Stamford, Connecticut

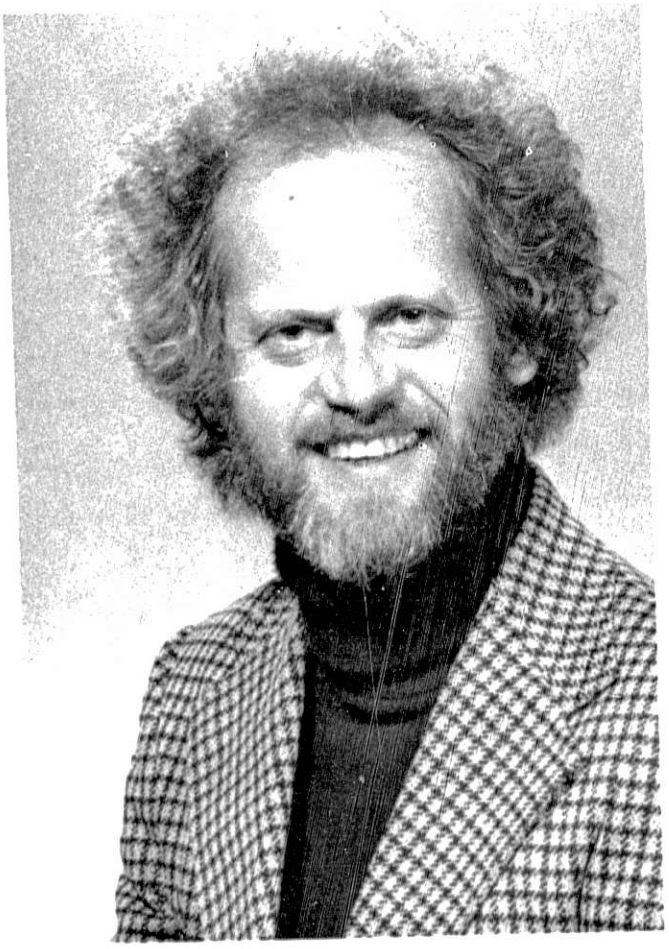
DISCUSSION PANEL MEMBER

M. N. Vardaman
CO_2 Acceptor Pilot Plant
Stearns-Roger Incorporated
Rapid City, South Dakaota

DISCUSSION PANEL MEMBER

R. D. Smith
Combustion Power Company
Menlo Park, California

DISCUSSION PANEL MEMBER



L. W. Kirsch
Components Technology Division
Argonne National Laboratory
Argonne, Illinois

DISCUSSION PANEL MEMBER

J. L. Powell, Jr., Chief, Equipment Branch
ERDA - Fossil Energy
Division of Major Facilities Project Management
Washington, D. C.

DISCUSSION PANEL MEMBER

J. W. Byron
Natural Resources Group
Phillips Petroleum Company
Homer City, Pennsylvania

DISCUSSION PANEL MEMBER

A. P. Klotz
Process Plants Department
Foster Wheeler Energy Corporation
Library, Pennsylvania

PANEL DISCUSSION

Roger Detman, Chairperson

Our procedure this morning will be to first allow each of the panel members to introduce themselves and give you some brief indication of their area of interest or expertise, and then we'll ask the audience to forward their questions for either a particular panel member or the panel in general. In the case of the general questions I will ask for a volunteer from the panel or possibly select a panel member to answer the question.

W. E. Schiesser, Lehigh University

Perhaps I should start by saying that I'm not directly involved in instrumentation for coal conversion plants, and you might then of course wonder why I am involved with the panel at all. I think the easiest way for me to explain it would be to say that we are developing, through partial support from ERDA, a tool which might be of interest and use to you in your considerations of instrumentation for coal conversion plants. This tool in particular is a computer code for the dynamic simulation of physical systems, and the primary justification for the development of this code is that it will be applied to the simulation of a coal converstion plant tentatively selected as the ICGG plant. However, this computer code is a general purpose tool that is designed for the simulation of physical systems modeled by ordinary and partial differential equations. The unique feature of this system, if there is one, is that it is intended to handle sets of ordinary and partial differential equations, and the reason we are attempting to do this is because many units, as I'm sure you know (for example, the tubular chemical reactor) have a significant spatial distribution as well as variations with time, and therefore, in order to model these units reasonably well, we have to consider both space and time in the mathematical model. That means we have at least two independent variables and therefore, when we write equations for such units we are naturally led to partial differential equations. Other units on the other hand do not have this significant spatial distribution, and they are therefore modeled by ordinary differential equations with time being the only dependent variable. However, these two kinds of units occur together in a plant, and therefore we have to be able to handle

systems of mixed ordinary and partial differential equations and that is what we are attempting to do. Now I'd like to show you the general capabilities of the system, and then show you some of the preliminary results which we have gotten, and I'm sure that this will take the time that I have available. I don't want to get into a lot of mathematics, but rather just give you an idea of what the system is intended to do. Figure 1 shows a general mathematical statement of the kind of equations it will handle, and I simply point out that the subscript, T, denotes time, and the subscript, X, denotes space. Therefore, these are really partial differential equations with dependent variables U_1 to U_N, which vary with both time and space. Basically, what the user provides is the coding for the functions F_1 to F_N as indicated in the following figure. Note that this is a very general formulation since F_1 to F_N can be a function of the independent variables X and T, and any or all of the dependent variables, U_1 to U_N, as well as the first-order spatial derivatives, U_{1X} to U_{NX}, second-order spatial derivatives, U_{1XX} to U_{NXX}, etc. This figure also shows a set of boundary conditions for the partial differential equations. These are applied at particular boundary values of X. The user defines the functions G_1 to G_M so that again, these are very general boundary conditions. Finally, the initial conditions at the bottom of the figure must also be defined by the user.

Well that's enough of the mathematics. If you are interested in how all of this is used, we do have a set of manuals for our system which you may request.

Briefly, I'd like to show you some of the results we have gotten. Figure 2 shows the axial temperature profiles for a fixed-bed methanation reactor. In this case the reactor starts out at a uniform temperature of 755°K; the transient response of the system then begins to evolve with time. Note that there is a pronounced temperature peak due to the exothermic reaction which moves down the reactor with time.

In Fig. 3, we see the variation of CO fractional conversion due to the methanation reaction, both with respect to time and distance down the reactor. And then finally in Fig. 4, we have the variation of CO fractional conversion due to the shift reaction.

$$U_{1T} = F_1(U_1, U_2, \ldots, U_N, U_{1X}, U_{2X}, \ldots, U_{NX}, U_{1XX}, U_{2XX}, \ldots, U_{NXX}, X, T)$$

$$U_{2T} = F_2(U_1, U_2, \ldots, U_N, U_{1X}, U_{2X}, \ldots, U_{NX}, U_{1XX}, U_{2XX}, \ldots, U_{NXX}, X, T)$$

$$\vdots \qquad\qquad \vdots$$

$$U_{NT} = F_N(U_1, U_2, \ldots, U_N, U_{1X}, U_{2X}, \ldots, U_{NX}, U_{1XX}, U_{2XX}, \ldots, U_{NXX}, X, T)$$

$$G_1(U_1, U_2, \ldots, U_N, U_{1X}, U_{2X}, \ldots, U_{NX}, T) = 0$$

$$G_2(U_1, U_2, \ldots, U_N, U_{1X}, U_{2X}, \ldots, U_{NX}, T) = 0$$

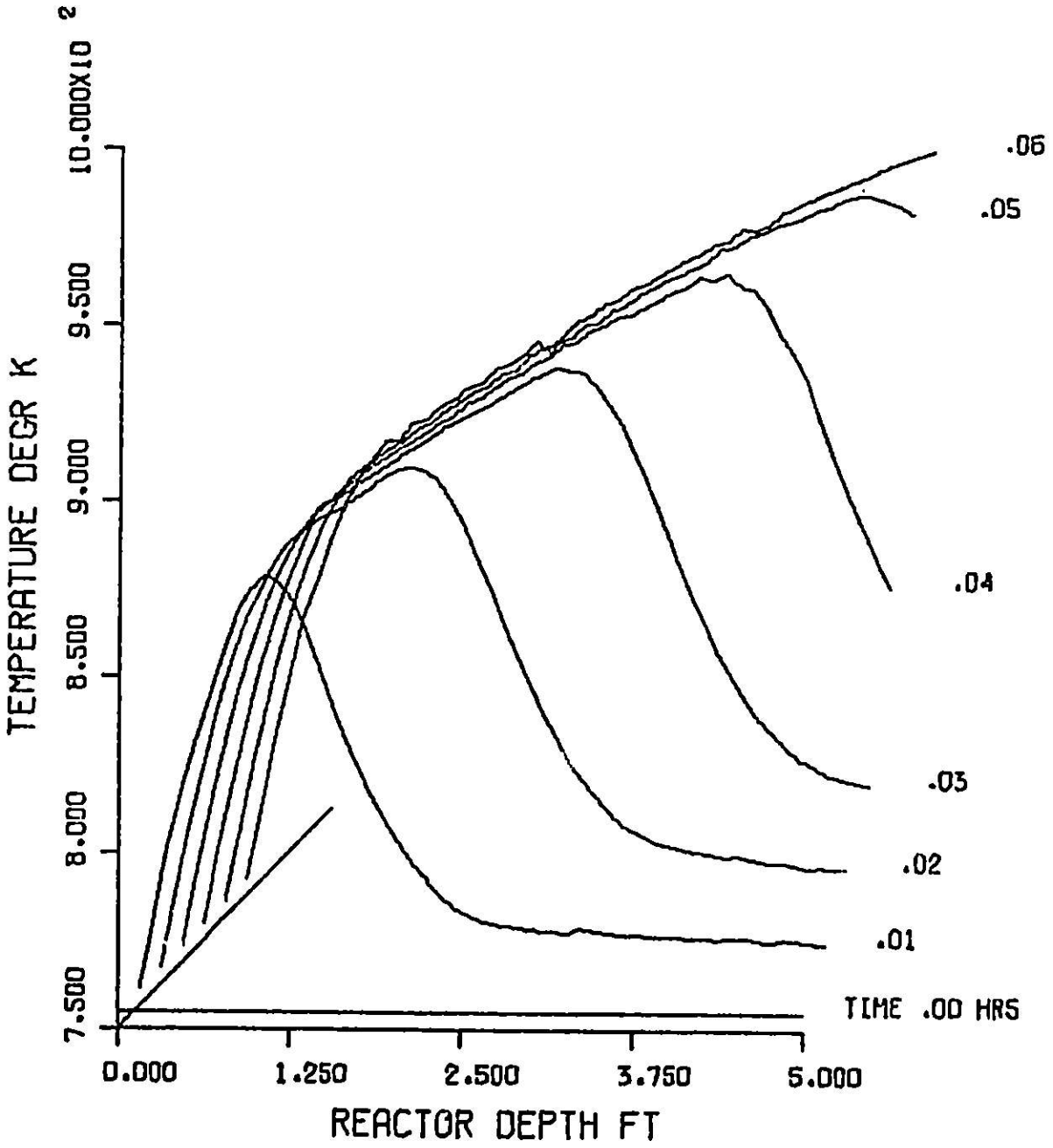
$$\vdots \qquad\qquad \vdots$$

$$G_M(U_1, U_2, \ldots, U_N, U_{1X}, U_{2X}, \ldots, U_{NX}, T) = 0$$

$$U_1(T_0) = U_{10},\ U_2(T_0) = U_{20}, \ldots,\ U_N(T_0) = U_{N0}$$

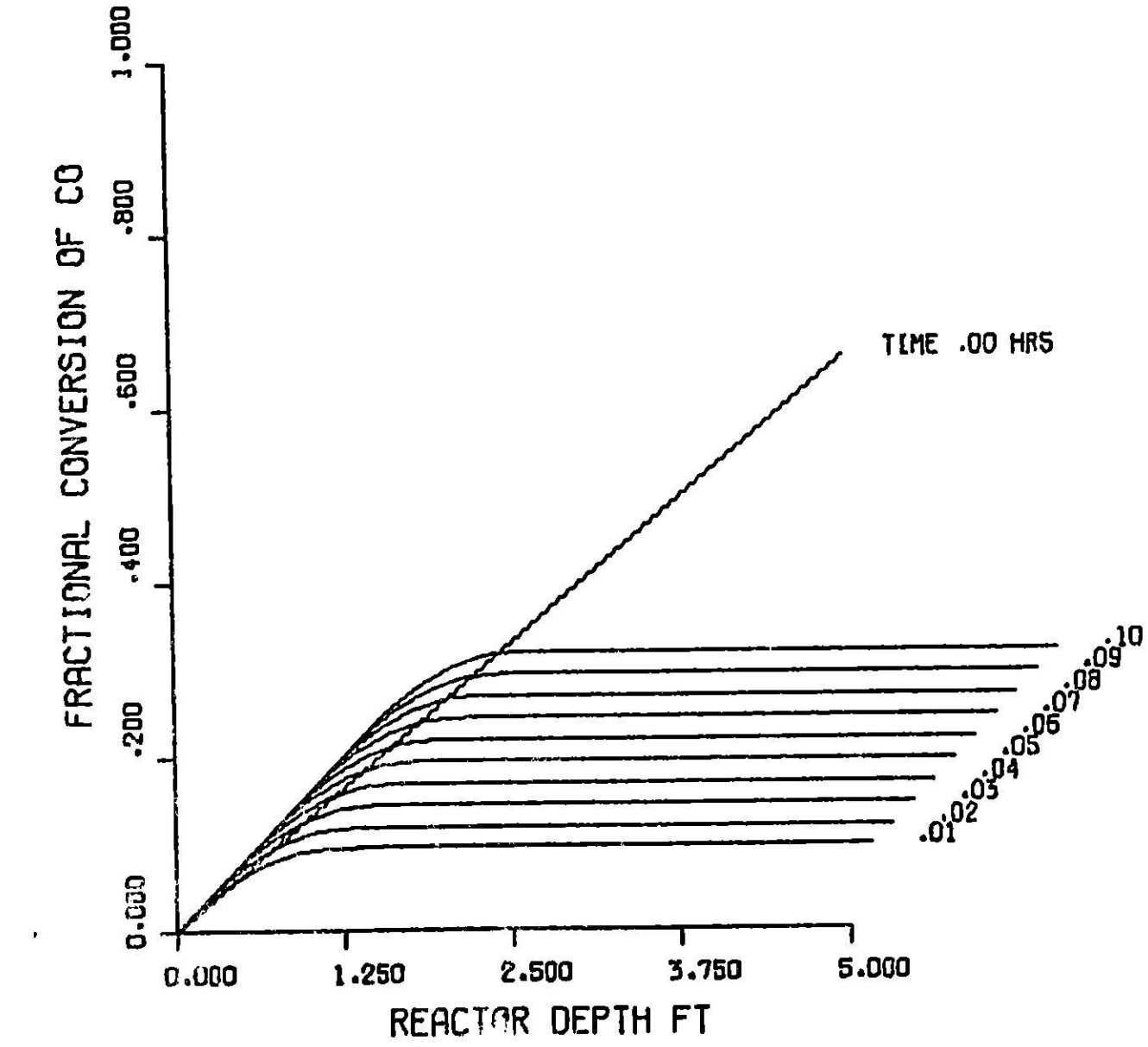
FIGURE 1. THE GENERAL DSS/2 ODE/PDE SYSTEM

Figure 2



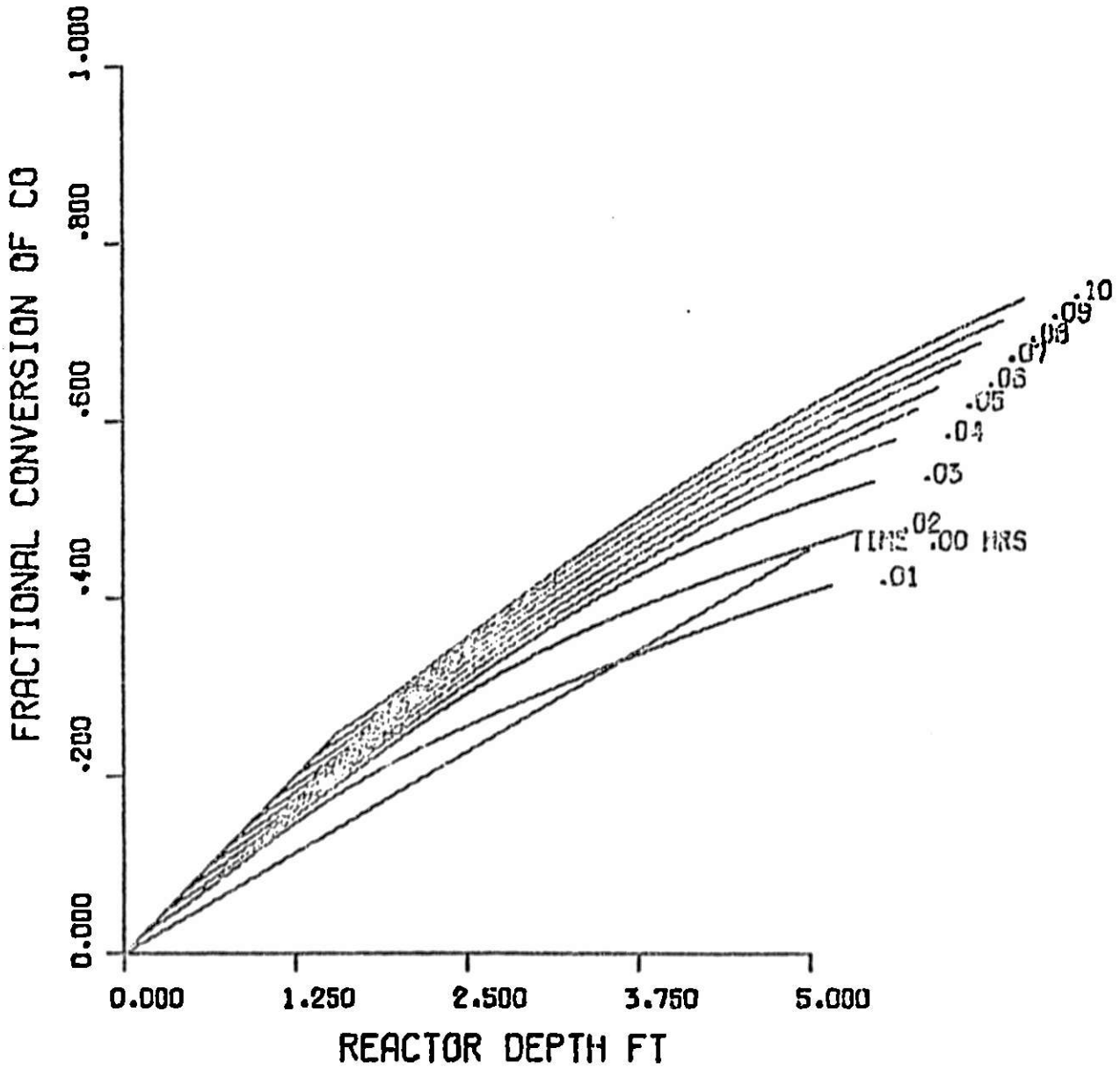
METHANATOR TRANSIENT RESPONSE

Figure 3



METHANATION REACTION CO CONVERSION

Figure 4



SHIFT REACTION CO CONVERSION

I think this will give you some idea of the general capabilities of the dynamic simulation code, and how it might be applied to a specific coal conversion unit. Thank you.

B. G. Lipták, Lipták Associates

I am an instrumentation consultant. Some of you might wonder what that is so I will give you a couple of definitions. If you have a pessimistic outlook, you might say that an instrumentation consultant is one who tells other people what to do and therefore he can be described as the mother-in-law of everybody. If you are optimistic, you might say that he works on problems which have been tackled by others but they have given up on these problems and therefore as my partners say, we make our living by doing things that "cannot be done".

Joking aside, maybe the role of an instrumentation consultant can be compared to the role of the bumblebee in the orchard, cross fertilization, or if you don't like a biological example, you can just simply call it technology fall out. Coming down here, I reflected over the last two years, and the things we've been doing. We've been involved in twelve different industries. When I say different, I mean as different as optimizing the energy conservation of sky scrapers to submarine guidance or from the more familiar chemical industry and refineries to pulp and paper and so forth. Working in this manner one tends to learn from one's clients and the knowledge gathered may benefit others as the experience from one industry tends to be beneficial to another.

As to my personal background, twenty some years ago, I was one of those Hungarians who thought that we could liberate our home land from the Russians, which should tell you that not all consultants are very smart. After an interlude of dishwashing I spent some fifteen years as Chief Instrument Engineer at Crawford and Russel which is an engineering and design firm. I instrumented maybe one hundred or so chemical plants, and during that period I had done a lot of publishing, including several books. During the last four years, I've been working in my own office.

As to the subject of coal gasification, I believe that this industry stands to benefit a great deal from the experience and advances made in the other processing industries.

I believe that more use should be made of non-contacting level and temperature sensors and of fast, onstream analyses with features of self cleaning and self calibration. I have quite a few ideas and I don't think I'm going to take the time now to get into detail. Maybe during the panel discussion we will get more specific on some of these subjects.

M. H. Vardaman, Stearns-Roger Incorporated

I am honored and happy to have been asked to participate on this panel. Presently I am the Plant Manager at the CO_2 Accepter Pilot Plant at Rapid City South Dakota, and I have been involved with this process since February, 1971. I think a word of explanation is required at this point. Stearns-Roger is the operating sub-contractor to Conoco Coal Development Company who developed the CO_2 Accepter process. The ulitimate responsibility for run programs lies with Conoco, but it's up to Stearns-Roger to implement and to operate this data in Rapid City. I have had various assignments at the pilot plant in Rapid City. I started out in charge of the engineering group. My next assignment was responsibility for the operations which was an advancement from the engineering. This was all phases except maintenance and accounting. Then in April, 1976, I assumed responsibility of Plant Manager at that facility.

The CO_2 Acepter process has developed from infancy to an operating pilot plant. That is not to say that all of the problems have been resolved. The first three years, 1972 to 1974, were spent in resolving mechanical, equipment, and instrumentation problems related to the relatively high temperature process, 1500° to 1800°F, with streams that contained solids with areas of corrosion and erosion. Process development was really not attacked until 1975 and 1976. In my opinion, it is unfortunate that this program is coming to a close. It's supposed to be shut down in December of this year. There is more work to be done on this process. I believe that there has been very good communication between our facility in Rapid City and the operators of various other coal

conversion pilot plants. Each group has their own day-to-day problems, which has limited the time for brain storming or think tank approaches to related problems, however, the CO_2 accepter pilot plant was one of the earlier operations, and has been able to supply information to other groups such as the Westinghouse low Btu process, Battelle agglomerating ash facility, the BY-GAS pilot plant in Homer City, Pennsylvania. Also we've worked with IGT here in Chicago, and ERDA's Synthane process in Bruceton, Pa. We all realize the experience developed at each facility should be utilized as a stepping stone for better and more reliable equipment for new PDU's, demo plants and later on, commercial plants. I feel that American technology has never lagged when the need was there. I'd be most happy to comment or answer any questions pertaining to instrumentation or equipment associated with the CO_2 accepter process and how it might relate to other types of plants. If there are any questions that might require drawings, diagrams, or written explanation, I'd be happy to develop these to be included in the symposium proceedings.

R. D. Smith, Combustion Power Company

My name is Dick Smith, and my involvement is more with the general management of equipment development programs, rather than instrumentation development, so in a sense we're the customer; we need the instrumentation in order to do the development. Our company's involvement is with the direct combusion of coal, which has led us very much into the field of high temperature gas clean-up as well as also to the field of fluid bed combustion. We are very much interested in high temperature filtration as applied to coal gasification plants as well as to direct combustion. We believe the same techniques apply. Our instrumentation needs are very much associated with gas cleaning measurements, particle sizes, the chemistry of the gas stream, all of these things we'd like to know right now. Because the chemistry of coal is very complex, you get a very complex product, and this has a lot to due with things that corrode, things that deposit, and almost everything that can foul up your operation.

L. W. Kirsch, Argonne National Laboratory

I have been at Argonne for nine years now. Like Bill Schiesser, I find my interest has been in simulation control. Right now we have a program with ERDA, in which we are attempting to quantify somewhat the instrumentation requirements in terms of their accuracy needed for controlling the processes in these plants. We do this by essentially taking the measurements and treating them as noisy processes in which the measurement is the sum of two variables one of which is the value an ideal instrument would read and the second is a random variable. The random variable accounts for any uncertainty in the process measurement and is assumed to be gaussian with known mean and variance. The problem as we see it is to see what effects changes in the noise properties, mean and variance, have on the controlled process. In this way we feel we can identify some of the instrumentations accuracy needs for these processes. I might add, that with the simulations we're considering we have a plant model, like Bill Schiesser does, and a physical property model. We're not out to reinvent the wheel, but we hope to interface as much as possible with any other ERDA programs who are developing both component and physical property models. Long range plans we might have are to look at the more severe plant transients. Now we're looking at transients around steady state operating conditions and in the future we hope to be able to go into the more severe transients, such as shutdown, startup, and hopefully look at ways for mitigating some of these transients. I will add that the system we're working with now is ordinary differential equations rather than partial, but really if you look hard at the model you will see that it's very closely linked with the partial differential equation model. Over the years at Argonne, I've been involved in simulation of many different types of systems, including nuclear power plants and steam generators. I would be glad to answer any questions along this line.

J. L. Powell, ERDA-Fossil Energy

I'm Jim Powell, and I think I've told you of that three or four times already and I'm Chief of the Equipment Branch of the major facilities project Management Part of ERDA. Our job in the equipment branch is total equipment, that is all the mechanical, electrical, and instrumentation aspects of this.

We are responsible for all types of processes that may come to the floor here, and which may become part of a demostration plant, that includes the gasification processes of all types, the liquifaction processes, boiler combustion, oil shale, and others that can be connected to any of those processes that are going to demo plant development. We will be heavily involved in the equipment part of it. We have been working on what we call critical components: A determination of equipment that goes into the plant. We want to set up a priority listing on those and accomplish as much testing as possible of those components prior to the installation in a going demonstration plant. So there is more and more importance of the instrumentation aspects of our job here and that will be true in any test of the equivalent duty of components and also later testing in the plant. Don't forget the one big item, namely, the control of the larger plants, which is going to be extremely important, because a deficit of a few percent of any major parameter is going to cost us a lot of product and it can also cost us a lot of money, and the money is limited even though the Government is a prime contributor. So I'll try to field the questions that you'd like to address to the Government, and I may be able to answer them, and if I can, I will. Thank you.

J. Byron, Phillips Petroleum Company

I'm with Phillips Petroleum at the BI-GAS Pilot Plant, and I've been with Phillips for eleven years working in the petro-chemical field and in R & D. I think I'm probably on the other side of the fence from most instrument people at this meeting; I'm one of the people who try the instruments more than designing them, or anything along that line. We are in the process of shaking down the BI-GAS plant and starting it up. I think everyone there is becoming more familiar with the instrument problems in coal gasification. We are also becoming more and more knowledgeable about some of the instrumentation that will be needed in coal gasification and many of the associated problems for instrumentation. So if you have some questions along this line, possibly I can handle them.

A. Klotz, Foster Wheeler Energy Corporation

Unlike many of you here and most of the members on the panel, I am not familiar with or have not been dealing with coal gasification. For the past two and one half years I have been involved in design of the Synthoil Process Development Unit, which is a coal liquefaction process. I have, however, looked at several gasification processes in which Foster Wheeler is involved, and most of the problems, or a lot of the problems, are very similar in both types of processes. The Synthoil process is a much higher pressure process but lower temperature than most of the gasification processes. Other than that, coal handling problems, slurry handling problems are very similar, and I'll be happy to answer any questions with regard to liquifaction processes that I can. Thank you.

PANEL DISCUSSION

QUESTIONS AND ANSWERS

P. D. Agrawal, Procon, Incorporated

Q. At what stage of completion is the Methanator Transient Response program at present? Are the results being published?

W. Schiesser, Lehigh University

A. The simulation I just discussed is for just a single bed of ten feet. The final objective is to simulate the RMP methanation system consisting of six reactors with interstage cooling. We are working on that right now and the results will be reported in our quarterly report to be issued on October 1.

P. D. Agrawal, Procon, Incorporated

Q. Do you plan to develop similar programs for the gasifier? If yes, for which process?

W. Schiesser, Lehigh University

A. Yes. We are developing a gasifier model now and a pyrolyzer model; I cannot give you all of the technical details because my colleague, Dr. F. P. Stein, is responsible for this phase of the work. So I quite honestly can't tell you too much about these models. My responsibility is for the development of the overall computer code and then I turn that over to the rest of our group and they use it for the modelling. However, if you would like more details about our gasifier model, or our pyrolyzer model, you could contact Fred Stein. The other thing I should mention is that there are two universities involved in this work. Lehigh is developing a dynamic simulation system, and Purdue University is developing a steady state simulator. The results are going to be made publicly available. Furthermore, the two universities are working together on the same flow sheet which is essentially the ICGG plant, and I hope that we will be able to compare the results of the dynamic and the steady state simulations when we complete our work through the next two years.

A. C. Tulumello, Delta Scientific

Q. To get a sense of the marketplace, what fraction of the total plant installation cost would you assign to the control instrumentation package?
Can you break the figure down?
How would you expect these figures to change in time?
Would you expect that the oil industry experience would be a good reference?

B. G. Lipták, Lipták Associates

A. This question was asked previously and I would say that the gasification process is similar to the petro-chemical processes, where the typical capital cost of instrumentation falls in the range of 4 to 8% of the total investment. This is capital cost as a percentage of the total installed cost. The total installed cost ranges from 6-12%. Just to identify the two extremes, to give you a feel, I would say that the 4% low limit corresponds to the kind of practices that exist in the coal-gas pilot plants which were described during the past two days. While the 8% would correspond to the kind of automation that was described for a refinery.

R. F. Detman, Chairperson

Q. How about the breakdown of these figures?

B. G. Lipták

A. The use of computers, the use of on-stream analysis, the use of automatic startup, automatic shutdown, the use of self-cleaning, self-calibration, these are the features which are responsible for going from 4-8% for capital cost or from the 6-12% on the installed basis. The reliability of computers can be expressed as a duration of failure of 4 hrs/year and a mean time between failure of 4 months.

R. F. Detman, Chairperson

Q. Would you expect this fraction of installation costs for the control package to vary with time? Or with experience?

B. G. Lipták

A. I would anticipate that the level of automation and its level of sophistication that has been described in the past two days would drastically increase. You look back ten years from today, and you will smile at the present level of sophistication. So yes, the trend is obviously up.

J. L. Powell (?)

A. I think we have to qualify that a little bit. The plant that will be partially funded by the government and partially funded by industry. We in government are bounded by some of the social economic problems that a lot of other commercial ventures are not, and even though we can put automated equipment in,in a lot of cases we are not going to be allowed to because we are going to have to utilize people, especially in isolated areas, where we have brought people in and built up the town, in order to support the plant, then you have to give those people jobs. So it's not just a clear technical approach that you instrument better, and you have to remember that.

R. F. Detman, Chairperson

Q. Do you expect the oil industry experience to be a good reference?

B. G. Lipták

A. Yes.

J. A. Consiglio, Solva-Tek Associates

Q. Short discussion on the topic, practical restraints from a plant design and operation point of view with respect to dilute phase-particulate mass concentration and size distribution instrumentation -- sampling probes vs. optical sampling.

B. G. Lipták

A. I believe that there is no question that analysis has to go in the direction of eliminating sampling altogether, and do analysis in real time. The tools are available; some of them are in use today. Devices like Environmental Data Corporation's unit, which is looking at the six or seven gaseous components simultaneously, or the Lear-Ziegler unit are

examples of that approach. It seems that the problems of the hot and dirty environment have already been solved. These devices work for stack emission type measurements today and are quite reliable due to the purge protection of the optical systems. The only area where additional development seems to be necessary is the high pressure area.

N. L. Kautsky, Stearns-Roger

Q. What has been your experience and problems with gas analysis, in particular discuss one or more gas components that have analysis difficulty. Please discuss sampling problems and solutions to-date.

J. W. Byron, Phillips Petroleum Company

A. I think that the gas component that has given us the most problems has probably been water and water vapor. Since water is a major feed into the gasifier, we have to monitor it not only as an input stream, but after the reaction is completed in the raw product gas stream. A subcontractor under Stearns-Roger, Applied Automation Inc., was successful at measuring water vapor as long as they don't receive slugs of water into the system. They use an on-stream chromatograph with the sampling setup heat traced and the chromatograph run a little bit hotter than normal, but as to the particular column in the chromatograph, I can't recall off hand what is used. They have been fairly successful, I believe, in getting the water vapor portion of the gas stream to give them a definite peak, which they can analyze for percent water.

C. K. Sanathanan, University of Illinois, Chicago

Q. Have you attempted to develop automatic control strategies using your simulation model? What problems do you anticipate?
Would you comment on the numerical problems and computer time requirements in your partial differential equation models?

W. E. Schiesser, Lehigh University

A. One of the intended uses of the code will be for the analysis of control problems, and of course, the other major application will be the analysis of startup. We haven't gotten far enough in our work to look at either one of these problems yet. We've just completed the first year of effort,

but we hope that the program can be applied to control and startup analysis. As far as the way we do the integration, there are two kinds of integration, one in time, and one in space. The one in time is done by a variation of the Gear method which you may know is really the most advanced kind of temporal integration available, and is widely used; so far it has performed very well. We have in our system for time integration applied some variations of this method; the options are determined by the form of the ordinary differential equations. The spatial integration is done presently by classical finite difference methods, and the user has the selection of three, five, seven, nine, and eleven point differences. We are also going to have some other methods for handling the spatial integration such as spline functions, but that is presently being developed, and is not ready for use.

S. M. Sung, Monsanto Co.

Q. Please describe how, where, and when to obtain experimental data to check your models. To what degree does your model take into account instrumental measurement errors?

L. W. Kirsch, Argonne National Laboratory

A. I would say this is probably one of the biggest problems with any dynamic modelling or static modelling is, how do you obtain the information, from where, and how do you treat the model itself after having obtained the data. About a year ago, I wrote part of a test program for the NRC for LMFBRs on both model development and model testing, i.e., large scale testing to verify models, and one of the most difficult parts of this program was how do you actually do the testing, what data do you need, and then what do you do with it. Another problem, as I see it, is that in most experimental facilities, the people running the facilities are generally interested in steady state information and it is very difficult to get these people to run transients which you think you might need to really generate the necessary information. In terms of fitting models, there are optimization techniques that one can use and are well defined, but I think this is a most difficult problem.

W. E. Schiesser, Lehigh University

A. I think this is very difficult. We just don't seem to have the data that we need.

W. H. Fischer, Gilbert Associates

Q. Is there a computer program for combustion or gasification chemistry that includes kinetics instead of equilibria, that can be run in a reasonable amount of CPU time and for which input data is readily available?

Is there a program that will consider partical ash removal in an MHD process?

W. E. Schiesser

A. Our methanation reaction system has kinetics in it because of the time dependency; we do not assume equilibrium. There are a number of parameters in that kinetic model which one can adjust. In fact, we have done this to try to match the output of the model with the reported temperatures and conversions of the RMP methanation system, and we feel we have a pretty good match. As far as models for MHD systems, I have never looked into those so I can't help you.

W. H. Fischer

Q. Not audible.

W. E. Schiesser

A. Our gasifier model will contain more reactions, but whether it will have kinetic constants or not, I don't know. We're putting the equations together right now, and they're getting more and more complicated and we may get to the point where we'll have to simplify it somehow.

L. W. Kirsch

A. I might add a little bit on that. There is an ERDA program to develop detailed transient gasifier models by Systems, Science and Software, California. I really can't say what the status of that program is now, but I do know that it's a three dimensional model, excuse me, they are

developing a series of models, three dimensional model to a one dimensional model, and the last report I saw from there, there were over thirty species that they were handling in this model. There are some quarterly reports out.

W. K. Fischer

Q. Not audible.

L. W. Kirsch

A. I believe it's a gasifier model. In terms of MHD I believe Argonne is doing some equilibrium modelling on MHD channels. Information on these models should be available from their quarterly reports.

W. E. Schiesser, Lehigh University

A. Purdue is developing a steady state gasifier model, and we hope to make use of their work. So if you would like to write to Prof. Reklaitis at the Chemical Engineering Department at Purdue, perhaps he could send you the quarterly report on the gasifier model.

J. P. Meyer, Oak Ridge National Laboratory

Q. Do you think that control problems associated with dealing with particulate laden streams represent a new dimension in control technology, or do you feel that there will be sufficient technology transfer from other industries to cope with any forseeable difficulties?
What unique dimensions in control technology do you think are associated with coal conversion technology?

B. G. Liptâk

A. That requires a long speach. I will attempt to put this in some sort of overall perspective. If you look at any new process, it usually goes through phases of development. Associated with it, there are levels of automation. The first phase of development, is at the pilot plant level. At that point, people are struggling with measurement reliability. Their main problem is that of sensor information, and as such they run their pilot plant more or less manually. So that's level one. That's where coal gas seems to be.

Level two would be when people have overcome the hardware limitations, they have arrived at a process which is reliable and they are beginning to understand the interrelationships between variables. This can mean for example that Valve No. 1 must open further when process variable No. 1 is decreasing. Later on one might start learning how fast or slow that valve should be throttled. That level two would be called closed loop control. It involves dynamics, it involves stability, but it does not yet optimize. It still concentrates on controlling levels and pressures and flows and temperatures. The plant is not producing or selling pressures, and temperatures, and flows and levels, but it is producing and selling coal gas. The purpose of the plant is to convert the BTU's contained in the coal into BTU's contained in gas at maximum efficiency.

The third level of development in any processing industry is optimized multi-variable control where you optimize the process while maintaining individual parameters within safe limits. The individual variables will tend to float, and you concentrate on controlling and optimizing what is really important: the efficiency of the plant or of production rate.

Now what is unique about coal gasification, the gentleman asks, and I don't think it is particularly the particulate laden stream aspect. I think technological fallout, as he puts it will resolve that, but what I think is unique is that the purpose of this technology is to provide us with a source of energy until we learn how to have a non-exhaustible source. Low BTU coal gas cannot be stored. It's not practical. Many people have gone through the calculations of what it would take to store it in a gaseous form, and it would require the earth to be hollow. Storing it in the liquified form, does not appear to be practical either. So what you are faced with is load following gasifiers.

The commercial size plant must be load following, and the load does vary. You know very well that electric utilities change the demand and the boiler has to follow it. So steady state experience as it exists today is completely useless from that point of view. What is required is a process control method to allow the gasifier to continuously follow the load. Load following can mean having several gasifiers so you can assign some of them at a time to meet the load or have the ability of individual

gasifiers to vary their gas production rate. So if you want to identify one single problem in which coal gasification facilities will require a higher level and a more sophisticated level of automation than either nuclear power plants or refineries, it is load following. We know that nuclear plants tend to be base loaded, refineries tend to set production rates for long periods. This is because the peak shedding of nuclear power plants is done by other types of energy sources, and because the refined oil can be stored in tanks. We cannot do that with coal gas; we have to have controls that continuously follow the load, so that as we make the gas, we use it.

R. F. Detman, Chairperson

Mr. Lipták would like to clarify a statement he made about storing gas. I'll let him explain his clarification.

B. G. Lipták

What I'd like to add is that when when low BTU gas is generated for the purposes of producing electricity it is not practical to store it. Natural gas or high BTU gas can naturally be stored and in these processes load following is not a serious problem.

J. V. Walsh, C.F. Braun

Q. Would you please discuss the problems you are encountering with your turbine as a result of dirty gas?

R. D. Smith

A. We saw a little direct erosion, and we did see deposition. The highest deposition was on the first stage stators, and is progressively less throughout the turbine. There is a compressor turbine and a power turbine, four stages in all, and the last two stages were virtually unaffected. Most all of the deposition and the wear were on the first two stages. Even though these blades were rotating at pretty high tip speeds, I guess about 1200 ft./second, you still have substantial deposition. There were still coatings on the rotating blades from the vapors that condensed and these coatings would entrain some ash. In other words the material at these temperatures, 1400 to 1600 F, does exhibit a sticky

characteristic. The usual type of ash slump test where you make a little pile and it falls over, doesn't really apply here, because these individual particles, particularly when they're small, tend to be very agressive in sticking to things, much more so than you would have believed before. The erosion arises from the fact that these small particles get together on the scrolls upstream of the turbine, and then they will break off. A whole chunk will go through the turbine, so that even though the particles themselves would be small enough not to hurt the turbine, something less than two microns, you can't afford to have very high loadings at all, because these accumulations will in fact come through the turbine in a big piece and they will do damage for you. During all of our testing though, as I mentioned earlier, we were not shut down at any time by turbine wear, or by turbine out-of-balance. It was a surprisingly tolerant turbine; of course, I hasten to add that the turbine does not have high stage loading. It's a relatively modest, industrial sized turbine, of basically an old design, but it has given us really a substantial amount of encouragement because of this ruggedness. The turbine operated at 1400 F metal temperature, and we did not experience any corrosion on the blades in the tests. We feel very strongly that the corrosion comes from about 1600 F on up. It is very sensitive to temperature excursions. All of this has led us to believe that if the turbine can be operated with a relatively low particulate loading, something on the order of 0.01 grams/std ft^3 the amount of material accumulation would be sufficiently small so that by shutting down maybe once a week, you could clean it. Cleaning would be accomplished with steam water, or maybe walnut shells, all of which are accepted practices in the industry. The material that accumulates, however, would have to be of such a chemical nature that it was not corrosive at the temperatures at which you were operating. In that regard, we are using additives, introducing them directly into the fluidized bed to counteract the sodium and potassium sulfates.

John M. Miles, Phillips Petroleum Company

Q. What is the status of the Synthoil pilot plant program?

A. P. Klotz

A. The Synthoil Process Development Unit construction will be completed. The process development unit will be used to develop the most promising high pressure high temperature liquefaction process available. The government will go out with a P.O.N. in November, 1977 and expects to award a contract in the Spring of 1978 on a cost sharing basis.

A. E. Knox, Argonne National Laboratory

Q. Please comment on the general nature of and performance of the control system used on the Combustion Power Company's fluidized bed combustor unit.

R. D. Smith

A. In building our pilot plant we had a rare opportunity that our system philosophy went a little counter to what Mr. Liptak was saying, in that we actually developed a control system along with hardware, which had its advantages and disadvantages. The advantage was, we got on top of it early and were able to really integrate the control system with the hardware, and in several cases actually the hardware shifted by virtue of what would be desirable for the control philosophy. On the other hand, of course, because we were plagued with hardware problems, we had to keep changing the control system as the hardware changed. Basically the heart of our system is the Texas Instrument 960A Process Control Computer, with a semiconductor memory and a disc memory. This provides the executive control for the plant. It is not different in concept from what was described for the refinery, actually. This unit does all the sequencing and programming of startup, using commands that command the valves open, check their position, check the rates, everything that's required in order to certify that the plant is in operable condition, and then actually programs the startup and monitors the sequence of bringing it up to load. The individual control loops on the bed temperature versus the solid waste feed, the electrical output of the generator versus the turbine inlet temperature of bypass control valve, all of those loops are individually controlled by analog control loops which can be controlled manually and can be disconnected from the computer, so that we can get in there. If the computer goes out, we

have full manual control of the system, and also we can perturbate it as one thing or another happens, which in development, it always does. We would to greater or lesser extents go on manual or automatic as we would have problems. The system is also designed to take data, and we use our memory in order to store the data from this system as we run, and also we can get a hard printout as we go along. The operator, operates the plant from a cathode ray tube display and he has a little schematic of the plant in front of him. Roughly every minute it updates all the parameters on the plant that the operators felt as meaningful. Apparently again from the refinery experiences, its pictorial display is very, very helpful. It's very helpful when things go wrong, because you can look at it and get pattern recognition. Also, it has the feature, that if the operator suspects that maybe there are accumulations in the turbine blades and the surge margin is deteriorating slowly, so slowly that he doesn't see the change from minute to minute too well, he can call up and ask the cathode ray to give him a graphical printout, a graphical display, of the surge module, let's say over the last twenty minutes. Then he can have that before him and he can spot any trends or any insipiant deteriorations. Just by trial and error we have learned to program different parameters that helped us quite a bit as a development tool. That is the computer's operation of normal load following. A point Mr. Lipták made which is true is that because we're looking at an industrial unit that sits with a big plant and provides its power and heat, it's got to follow the load of the plant.

W. S. Su, Stearns-Roger

Q. Please explain your "envelope control" concept in practical applications. Have you ever used that concept in any project; which and how?

B. G. Lipták

A. Yes, I have used it in the chemical industry. (See the article in September 1977 issue of Instrumentation Technology.) I did not use it in the coal gas industry. Maybe I should explain what the envelope control concept is. Any process serves a particular purpose of generating a product or meeting a service. The pressures, the temperatures, the levels, of the flows internal to the plant are just incidental

necessities having to do with the (electrical) characteristics of the plant. Traditional control is inefficient, because a control valve is dedicated to maintaining a process variable and because the set-point of the process variable is fixed. Traditionally the worst enemy of control progress has been the concept of single set-point control keeping variables constant at some arbitrarily fixed value. Why? Because that's how it's been done in the past and we've found that particular value to be acceptable.

Envelope control in a broad sense means that we look at all the various parameters as constraints which we cannot violate (such as the bed level in a fluid bed; we cannot increase beyond a certain point and we cannot collapse the bed, but we have the freedom to vary it) temperatures, pressures, even material and heat balance related aspects of the process are in the same category. Having released ourself from the limitation of single set point and having chosen two set points within which the particular parameter is allowed to float you have identified control evelope. (For details see the article in the December 1975 issue of Instrumentation Technology.)

On a Westinghouse project which I worked on in 1973 (and I presume the gentleman has read my report which was published in 1975, and I understand ERDA has submitted a patent application based on it in 1976) we have identified some 27 parameters of that particular gasifier as constraints, as parameters that are important to be maintained within safe limits. But as long as all of them are within those limits, the gasifier can still be optimized in the sense of efficiency, of moving the maximum number of BTU's from the coal into the gas. This I understand has been modelled in the Westinghouse Research Center, but I'm not very familiar with the details of its status, and so that's all I can say about envelope control in coal gas industry.

Envelope control elsewhere has proved very substantial results. We applied envelope control to chiller optimization, and in some cases cut the cost of chiller operation in half. We have applied envelope control to building air conditioning systems (see ASHRAE Transactions of February 1977 Conference in Chicago) to make the building self-heating in the sense of taking the heat which is generated by the core of the building in winter and transport that to the perimeter where the heat is needed.

In those applications it has been successful. People in the Chemical Industry have also used it in unit operation optimization.

Dick Duffey, University of Maryland, Argonne National Laboratory

Q. Can you comment on the time schedule for the demonstration plants and full scale coal conversion plants and relate this to the need for instrumentation?

J. L. Powell

A. Right now, we have the two contracts which were mentioned previously by Mr. Rial, with ICCG and with Conoco Development, and these are the first of a series of plants; they are the furthest along at least in our procurement cycle. In the next 20 and 22 months time scale we expect to accomplish a conceptual design, and then a detailed design and we expect construction to start on one selected plant which is presently authorized in the 1979 time period. Then of course, the construction time is estimated between three and four years, and then you have about an additional six-month startup period for stabilization of the total process of the system. So we're talking in the 80's, 1983, 1984, 1985 time period to have something on-stream.

D. J. Stopek, Commonwealth Edison Company

Q. With the high emphasis of all programs on data gathering, the development of reliable instrumentation is paramount. However, is any instrument better than the sampling system upstream? All of your programs have progressed through the learning curve of sampling systems. Do you have any publications describing your failures and successes? If not, I feel that it might be a valuable pursuit which would aid all researchers in the coal conversion field. Please comment.

J. L. Powell

A. I'll have to comment here that the pilot plants of course are handled by different groups than ourselves. The data that they generate is contributing to our understanding of the demonstration scale plants, but it does not supply all the answers. We really have a different instrumentation and control problem, in degree, than you do in the

pilot plants. Remember that we are to prove not only the process, which the pilot plants are primarily there for but also see if the chemistry is O.K. and see if it all ties together. The pilot plants do not even have the total components many times that we have to have in a complete plant. When we come to a demonstration scale, we are to prove the economics, its operability, its reliability, its ability to produce product so we are much closer to commercial reality than we are to R&D reality, but we unfortunately have a mixture of both. With the extended time scale that I mentioned before to answer the part about the sampling area, undoubtedly we will have to use some instrumentation and control systems which we don't really like. I do not think that's the best solution, but in the time frame that we are going to be operating, we are going to be forced into that posture. We do have a different set of problems even though they are related. That is one of the things, that we hope we'll be able to get: those items that will really work, do the the job and that are advanced. We want them, and we are going to have to have them to do the best job.

D. D. Bruns, University of Tennessee

Q. Does the panel feel that modeling of the processes under development and control algorithms needs are being generated in harmony with the building program?

L. W. Kirsch

A. There are quite a few modeling programs being undertaken by ERDA; I mentioned the gasifier program, of course, Bill Schiesser in the Lehigh program, the Purdue program. MIT has a large contract to develop a steady state simulation package for coal conversion plants. The program scope includes both plant components and physical property models and is targeted for completion in 1979 or 1980. With this program they will be able to look at both economic and steady state process analysis. They have also stated that they would like to make the system compatible with later dynamic simulations. We have our own program, and again I mention Bill's program on which they are working with Purdue. In terms of are we keeping abreast, I really don't know. It's going to depend on how well we can get the modeling done, and how we can verify these

models with test data to see that they do give realistic results. At present, I can't say what the feedback from the modeling programs to the actual plants might be.

J. L. Powell (?)

A. One thing, remember the time line I was telling you about here. Within a two year time period, we will start construction; we plan to. If you back off then you have to come up with a cut off date on your design and freeze it. I think you can see that these programs are one, two, three years off until a utilization point is there, that we can believe in. So we're going to be having to do a lot of it with the best that we have right now, from the modeling, so it's going to take the best brains and thoughts that we can get together.

W. E. Schiesser

A. I've been asked to speak into the microphone. At Lehigh I lecture to 275 students at one time and since the PA system is always breaking down, I've learned that shouting is the only reliable way of talking to such a large group.

When we started our project we were told by ERDA that we would be given access to the details of a coal gasification plant, the ICCG plant; I want to be rather careful because it is a sensitive area, but quite frankly we have not received those details, and I'm not sure we are going to. And I really think that as far as the practical application of our computer code is concerned, probably the most serious problem we have is getting the detailed information that we need in order to model the individual units. I just don't know how this is going to work out in the final analysis, but right now it does not look at all encouraging.

J. L. Powell (?)

A. The negotiations have been going on for over a year, and the prime hangup has been the secrecy, and the secrecy agreement that they have finally signed here allows a limited number of government people access to certain parts of the process. Now whether that includes Lehigh, I'm not sure. We had the best of intentions, in the beginning.

Unidentified

A. One comment; in the direct combustion area as opposed to the gasification pilot plant, which is of course an order of magnitude more simple, the MIT program which is picking up steam and moving well. These people are in touch with the people who are doing the hardware. We have direct communication outside of the normal channels, and my impression is that the first hardware tests will be in long before the model is done. But the two will reinforce each other and I have the impression it will be very powerful and useful to those who are concerned with hardware.

T. Gozani, Science Applications Inc., Palo-Alto

Q. When you have a successful and reliable instrument that cost little and affords large saving to the industry it is very easy to get the industry acceptance. How, however can we gain that acceptance to new methods, technology, or instrumentations which are not cheap and their main promise can be realized and appreciated once the new instrument is put on line and is not treated, at least initially as a black box. A case in point could be the Prompt Neutron Activation Analysis for elemental analysis of coal.

J. L. Powell

A. I'll try to field that one, but I'll have to speak indirectly, of course. What we have to do with the time line that we are talking about is to set initial priorities on what is the biggest problem, what is the most pressing problem, and this problem of priority setting should be based upon the earliest need. The earliest need is in the gasification, the high BTU, and followed by the low BTU, which is the way our construction schedule is planned. This prioritizing is not quite here, it needs more developing and more tests. We're going to have to make an assessment as to how much risk we are willing to bear, and that risk assessment is not just ours, either (that is government). It is also industrial partner's; he's part of the decisions. He's using risk assessment just like we are, and I think a lot of times he even has more to say. In order for you to sell some piece of equipment that you're presenting, you'd have to convince the industrial side as well as the

government side. Maybe you could do it simultaneously. The main thing is first things first. We have to get the best plant that we can in the assigned time frame. So a lot of good ideas are going to have to be held back, until we get further down into the program. There is no other way. We are facing a real world here, and the real world is the commercial partner.

T. P. Mulcahey, Argonne National Laboratory

Q. What computer will your code be operational on?

W. E. Schiesser

A. Right now it's running on the Lehigh CDC 6400. We are also committed to developing a transportable code which will be available to anybody who would like to use it, which means that we are writing it entirely in FORTRAN IV. We have sent the prototype system, that is, the code up to the present time as it now exists, to Oak Ridge, where it can be used by anybody who is interested in it. There it is on an IBM 360 model 195, and it's now running. We've also sent it to ERDA at Aberdeen, and there it's running on a Univac 1108. Also, apparently other people have heard about our work and have requested the program, and we've sent it out to about a total of ten other companies, universities and government agencies. It's running, as far as I know, on an IBM 370, a PDP 11, Sigma 7, a CDC 6500, and a CDC 6600. Ultimately, we hope that it will run on most of the major computers that have a good FORTRAN IV compiler.

J. F. Schooley, NBS

Q. What fraction of the "US Coal Reserves" will the processes discussed this week be able to utilize? If 80-100%, terrific! If less than or equal to one half to two thirds, does anybody have any more good ideas?

J. L. Powell

A. I might point out that the various processes have a variability and a capability to handle different coals. For example, you heard earlier that the BI-GAS process will handle any kind of coal because it's an entrained type of unit and the agglomerating tendency of coal

is not a problem. Conversely, the CO_2 acceptor process is designed primarily to handle lignite or possibly sub-bituminous coals, and cannot handle bituminous caking coals from the Eastern part of the United States. In the case of other fluidized bed processes, some coals can be handled more easily than others, because of caking properties and so forth. Now with respect to the coal reserves, the utilization depends on the size of the coal deposit to some extent. It is not practical to build a full-sized commercial coal gasification plant until the coal reserve is there for at least 20 years, and there is a good portion of this recoverable coal reserve that is in smaller deposits that required for that type of plant. So there is a problem with utilization of smaller coal deposits over the long run.

D. M. Field, Illinois Coal Gasification Group

Q. Yesterday, Mr. Bailey of C. E. Lummus went through an outline of instrumentation development, specifically bed level, bed density and pressure, made necessary through problems in startup. Have either CO_2 Acceptor or BI-GAS had similar startup experiences? (a) If so, did you attack the problem in a manner similar to Synthane? (b) Did you arrive at a similar standard for installation of DP cells and purge systems? (c) Finally, did you document your development work in a report similar to the one distributed by ERDA-Synthane?

M. H. Vardaman

A. Unfortunately, I'm not familiar with the documentation on the Synthane process. Yes, we did have problems in knowing the bed levels, the bed densities, and temperatures at the start of operation in 1972. I'll try to give a verbal description of how the reactors were set up originally. Both the temperature and differential pressure measurements were by two-inch diameter pipes, suspended from the top vessel heads. One vessel was roughly 35 ft. long, and the other one is 60 plus ft. The associated problem there was that the tubing for the instrument was 1/4 inch tubing inside of the two-inch pipe. These projected from the pipe at a right angle. These plugged almost instantaneously, plus in the generator where we operated at 1800°F we made spaghetti from the two-inch pipe; it dropped off and curled up in the

vessel. We did what to us at that time a major modification. We went through the walls of the reactor. Both of our vessels have a water jacket which means going through two layers of metal, and the inside one is the pressure-containing wall which varies from an inch up to about 2-1/2 inches thick (the reason that the material was made thicker in some areas was for reinforcement for the larger nozzles). What we've designed is a 3/4 inch stainless steel pipe passing through the metal wall and refractory and extending into the bed approximately three inches. Inside of the 3/4 inch pipe is inserted an 1/8 inch schedule 80 310 stainless steel thermal well which we constructed in Rapid City. Then inside the thermal well we have a thermocouple. The annular space between the 3/4 pipe and the 1/8 inch stainless pipe is used for differential pressure measurements. Each side of the DP cell is purged into the vessel to keep the opening clear. This has worked very successfully. Also we have redundant probes on the vessel where we can determine both level and bed density. Most of the time we calibrate our differential pressure transmitters either to read directly in bed density or some multiple of bed density. The reason for multiple, is to have the instruments to read 0-100. If we can fit within that range with 40 or 50 lbs/cu. ft. we'll take a direct reading. With some of our densities we're looking at a heavier material since we do use limestone as an acceptor in our process which is over a hundred pounds per cu. ft, therefore we use some multiplier to come up at bed density. On temperature measurements, as I said originally, they were also suspended from the tops of the reactors. Now they pass through the same pipe where we get our differential pressure readings. We have very little problem as far as temperature measurement in the gasifier which operates at 1500 to 1520 F. In the regenerator, at our nominal 1850 F, thermal wells and thermocouples last five to seven days. We can replace our thermal wells while in operation by using a compression fitting. With the 3/4 inch pipe, we have two block valves, and at the outside block valve we have a compression fitting that allows us to remove and insert new thermocouples and thermal wells.

J. W. Byron

A. In our particular case, we run an entrained bed, so bed level, per se, is a problem we have not had to worry about in the gasifier. In the

methanation section we do use, or will use, when we get to that point, a fluidized bed methanator. Since we haven't operated it, except for limited testing, I can't give you any specifics there. We do run ΔP measurements on the gasifier between the slag quench zone and Stage I; between Stage I and Stage II across a venturi separation, in these cases I think its been simply a matter of being effective in our purge on the ΔP instrument leads. I think in our case most of the purge rates are set with restrictive orifices and their rates are not specifically controlled aside from changing pressure on our purge gas, an increase in pressure on the purge gas system gives additional flow. Right now, these purge rates are areas that could be giving us some problems in our material balances around the gasifier in that we don't specifically have a handle on each flow. I think our total purge rates to the gasifier are something like 40,000 cfh.

M. H. Vardaman

A. One thing that I should mention, the CO_2 Acceptor Process is not operating at the same pressure as IGT's HYGAS or BY-GAS. We operate at 150 psig rather than 1000 to 1500 psig. We therefore are able to use rotometers rather than restricting orifices for measuring the purge flow. We use, in our entire plant, in the neighborhood of 7,000 to 10,000 cu. ft. per hour for total purges. One thing I didn't touch upon is this documented? I believe the answer to that would be yes, because there have been two annual reports issued. I know for sure that one of them is available through the NTIS; I believe that the second one is not available through them, but I believe that if you contact Dr. Lowell Miller, with ERDA, that it would be available.

E. S. Giordano, Badger Plants Inc.

Q. What types of instrumentation are available or will be available to measure slag bath level in a high pressure (500 psig) gasifier at 3000°F.

J. W. Byron

A. Measuring slag bath level?

Chairman

I think he has a misconception of how, for example, the BI-GAS gasifier operates. So perhaps you could clarify that.

J. W. Byron, Phillips Petroleum Company

A. We're attempting to tap the slag on a continuous basis. The molten slag pours or falls out a tap hole to a water filled quench section. From the quench section the broken slag frit falls into lock hoppers for removal. We're monitoring our slag flowing operatings with a TV camera, which looks through the cooler portion of the gasifier quench section directly at the slag tap hole and through view ports. Another handle that we do have on the process is a measure of ΔT across our cooling water tubes in Stage I. During start-up and at basic conditions without char feed in the gasifier, we have a particular ΔT that gives us a heat loss numbers. The ΔT may be up as high as three to five degrees F in the cooling water in that set of operating conditions. As the slag containing char is introduced into the gasifier, the ΔT on that cooling system proceeds to drop as we coat the tubes or foul the heat exchanger, or whatever you want to call it. So we do have that handle telling us how our slag build up in the Stage I portion is progressing and then we can also start looking for indication of slag tapping through the TV camera or through view ports.

E. S. Giordano

Q. Not audible.

J. W. Byron

A. You are talking about a specific slag bath or slag contained in a specific area, and how they measure it? The only thing I can do is guess and say that if you had a purged, cooled view port, a TV camera or something like this where you could physically watch, you could check your depth. Thermocouples seem to get eaten up in the slag, they flux off with just about anything you can put in there. With thermocouples another possibility is coolant ΔT which will tell depth if you've specifically broken the cooling system out cooling tube by cooling tube and with special matched RTD's, I can't give you a much better answer than that.

B. G. Liptak

A. I would think that in hostile environments, such as the gentleman describes, one ought to at least give considerations to non-contacting methods of measurement such as gamma radiation.

T. K. Lau, ERDA

Q. Please comment, from you plant design and operation experience, on practical instrument response time requirement for on-line control.

Unidentified

A. Were you referring to computerized control, or just the existing technology such as has been in existence for the last five to ten years?

M. H. Vardaman (?)

At the CO_2 Acceptor Plant I can't tell how fast the response times are because some of the analyzers are four to ten minutes, lagging what is actually happening in the process. As far as differential pressure, temperature, and flow, I'd have to say that that is essentially instantaneous. We have no computerized control, it is standard state-of-the-art type of control. I believe that what we have for our process is adequate, and we do have a data logger that has been in operation for six or seven months which would have the capability of going to control, but we have no intention of using it for that. It was installed strictly for data acquisition and logging.

J. W. Byron

A. For our on-stream gas analyzers, I think it requires something like eight or ten minutes on one unit that is strictly dedicated to one particular stream. So that looking to control gas from your component output on your gaseous streams, I think right now about the best we could get is about eight minutes. If you want to look at one particular component in a gas stream with a specific analyzer for that particular component, the time required for analysis would be quite a bit less. We are in the process of moving an oxygen analyzer from a point quite a bit down stream of the gasifier to a sampling take off that we have in Stage II, in the

high temperature, high pressure zone of the gasifier. The response time on that unit is somewhere within a very few seconds.

But that's the state right now of the speeds and times of gas analysis at BI-GAS. Now in the process items, since we have pneumatic instruments we have to figure in some delay for quite long lines in the pneumatic control systems. It's not instantaneous on differential pressure or flow or something like that, but it's in the order of a few seconds.

B. G. Liptak

A. In the chemical industry we use the rules of thumb of selecting sensors with dead times that are two orders of magnitude faster and with time constants that are at least one magnitude faster than the process which we are trying to control. Maybe I should explain what dead time means. You change something to the process and for a period, nothing happens; that's dead time. After the dead time has passed there is an S-shaped reaction curve that evolves and the slope of that is a function of the time constant.

C. R. Fleming, The Foxboro Company

Q. Several prominent I&C product and system suppliers are represented in the audience. Collectively they will be spending in excess of fifty million dollars for RD&E in the next twelve months. How would the panel like to see this spent relative to the constraints within which they are currently working?

J. L. Powell

A. I don't know what contraints you're working under, I'm sure there are many. It is hard for us from this point in time, from the demonstration scale, to tell you exactly which one is the most important, which series or which types of instruments. We are going to need practically anythings that fits as early as possible. We have to become familiar with what you are doing before we can make any kind of a decision. The rest is up to you.

M. H. Vardaman

A. Are you referring to what areas should this money be spent? The areas that I have observed from experience in Rapid City are: number one, temperature measurements such that you don't have to replace thermocouples every five to seven days. Number two, is in particle size distribution and are they consistent within the lines such that you do not have to take a sample from the system to be able to determine what's flowing through that pipe, quantitative as well as qualitative. The way it is now, you have a time lag from a sample to analysis from an hour to eight hours before you know what size material is going through that line. Needless to say, by the time you get that sample back you know what it was then, but you sure don't know what it is at the present time.

M. K. Shieh, Jeffrey Manufacturing

Q. Would you consider to include instrumentation and control for coal preparation plant in the next symposium?

J. L. Powell

A. Certainly. The next time around we hope to have quite a broad input of problems which have a little better definition by that time. And coal preparation is important to all the processes, so I'm sure we consider that as a fairly high priority item across the board.

W. S. Su, Stearns-Roger

Q. From your experience, do you feel if computer closed-loop control could be used in the CO_2 Acceptor plant?

Chairman

Just a simple yes or no will do.

M. H. Vardaman

Q. No.

C. K. Sanathan, University of Illinois, Chicago

Q. What benefits could an instrument developer get from your efforts at Argonne? For example, could he get an estimate on measurement

accuracy required for a specified degree of regulation of process variables?

L. W. Kirsch

A. I would hope so. To expand on that a little bit, what we are attempting to do is to really quantitatively define what types of instrumentation accuracies are going to be needed for a particular process. The program scope is to concentrate on those major instrumentation research and development areas so that we can get feedback back to the people who are working in these areas as early as possible. I would say yes.

V. S. Underkoffler, Gilbert Associates

Q. Please compare the expected level of particulate loading and alkali metal concentration at the inlet of the gas turbine when a pressurized fluidized-bed system is used.

R. D. Smith

A. The specification for a gas turbine is one hundred times higher than the numbers that I gave out, and the specification is based on the normal commercial usage which is considered very safe. We feel, and I believe that the major turbine manufacturers would agree, that this is really a whole new area of R&D. Their specifications are based on field criteria and they are anxious to learn as well as others in the field as to what the true limits really are under these new conditions.

E. E. Geraci, Leeds & Northrup

Q. To what level must hot gas particulate be cleaned in order to use with a gas turbine for continuous operation. Express the answer in terms of loading (grains/scf) and size (microns).

R. D. Smith

A. We would say essentially for a particle size of two microns and below, a level of 0.01 grains per dry standard cubic foot, or less. Above two microns, essentially nothing. There is another criteria which would be the specification of the alkali vapors and I'm afraid at this point in

time we can't offer any numerical suggestions. But there will definitely have to be limits there.

D. D. Bruns, University of Tennessee, Chemical Eng. Dept.

Q. If thermocouples are used for temperature measurement, what specifications are needed for control purposes? Specifically what lifetime is reasonable, what response time is needed and what accuracy and calibration stability are required?

Chairman

A. Mr. Vardaman has said that the lifetime that he has experienced so far in the CO_2 Acceptor is several days, which is unsatisfactory.

M. H. Vardaman

A. For the regenerator which is 1850 F, several days, and our gasifier, say several months. Now the accuracy, I consider what we have as around 2%, which falls within the realm of 20-40 F. Now the question is whether or not that is adequate. For an R&D level of knowledge it is probably is not.

Chairman

Q. Response time is no problem as I understand it, on thermocouples?

M. H. Vardaman

A. I don't believe it is.

Chairman

Q. How about calibration stability? You don't have a problem with that either, do you?

M. H. Vardaman

A. I don't believe that we do.

F. Bondy, Foster Wheeler Energy Corp.

Q. To what extent was it necessary to monitor product particle size distribution from your pulverization unit at Rapid City?

M. H. Vardaman

A. Our gasifier was designed to handle from eight mesh through a hundred mesh material. If we run more than 10%, at the very outside 15%, below 100 mesh, the material will blow overhead and will not be gasified. Therefore, we do operate our grinding system to minimize the -100 mesh material. And again, this gets back to being able to determine the size distribution leaving the grinding area. We obtain a sample that is leaving the system, take it to the lab where it has to be cooled, because it's about 300 F leaving our grinding area. We have a roller mill that is supplied with a 1000 F gas to dry as well as pneumatically transport the material to an elevation about 165 ft. above ground. The screens in the laboratory must have the material cooled down to around 150 F before it can be screened, so there is a time lag in the neighborhood of one hour before you can get results back. If you had instrumentation, you would be able to look at this pneumatically transported material, then have results on quantity as well as a distribution. One then could make a change instantaneously or within a short period of time.

F. Bondy

Q. Did the plant employ valves in hot solids throttling service? If so, how high was the temperature, what type of valves were used and was satisfactory service achieved?

M. H. Vardaman

A. The valves that were used in the 1500-1800 F solids carrying stream were butterfly valves. They are not gas tight. They have about 35,000ths clearance around the edge for expansion; simply a shaft with a wafer, and these work very well in my opinion. We have a device on these valves that we call a kicker. They are pneumatic valves and we impose two pounds additional signal to the valve every fifteen seconds so that they move and are not in the same position all the time. We obtain relatively smooth control and consistent flow through the valves with this method. The valves range from two-inch up to five-inch in diameter. The valve is a sleeve which is backed by refractory and then the pressure containing portion ranges from eight to fourteen inches depending upon the line size. Those lines are carbon steel with insulating refractory, and the inside

is either a metal sleeve or a refractory sleeve. The first refractory line that we used was installed last fall, on an experimental or test basis, because we wanted to use air to transport our acceptor back to our regenerator, and I am quite please with its operation.

W. H. Fischer, Gilbert Associates

Q. It is my impression that EPA particulate limits are excessive for turbines. What is a suitable grain loading and size distribution for turbines? Gas turbines? Are they different for combustors than for gasifiers?

R. D. Smith

A. In terms of EPA loadings in turbine systems, it sort of came about in a backward way, particularly for solid fired turbines, because we're using incinerator or steam power plant criteria where the excess air is 10% or 15%. Turbines work on an entirely different cycle and so you have to ratio the numbers back. The criteria mentioned earlier that we feel are required is .01 grains/dry scf for the turbine, which is roughly comparable to the EPA requirements.

Nancy M. O'Fallon, Argonne National Laboratory

Q. Please describe briefly the control strategy for the CO_2 Acceptor pilot plant. What do you consider your most serious problems in instrumentation and control?

M. H. Vardaman

A. We have a two vessel system, the regenerator which contains the acceptor, and the gasifier where the coal is gasified with steam and the heat is supplied by circulation of calcined acceptor. There is a pressure differential which is maintained between the two vessels by means of a gravity solids flow line, where we have one of the before mentioned butterfly valves. The line between the two vessels is roughly 30 ft. long, and at about a 70° slope. Across this valve, we maintain on start-up, a differential of 8 psi, and after we progress into the run a differential as low as zero psi but, normally one to two pounds. We take gasified char from the gasifier and transport it to the regenerator to

supply fuel for re-calcining of the acceptor. The main control problem, I would say, is the ease and reliability of obtaining gas samples from the system. This refers to what Mr. Byron of Phillips said, that water is the most difficult to analyze in order to know what is the percent water in the gas stream leaving the gasifier. Our dew point of the gas from the gasifier is 350-400 F which means that all sampling lines have to be heat traced, even above it's dew point and of course, there are 300-400 mesh particulates in the sampling line. We have built a sampling system where this gas stream flows to a condenser and is cooled. The water is then weighed and the dry gas is metered. We've spent ten to twelve months trying to perfect a chromatograph which would give us water content as well as non-condensables from the gasifier with no success. It will give us the normal components, but it will not give water reliably.

T. P. Mulcahey, Argonne National Laboratory

Q. What degree of model sophistication do you feel is necessary to develop plant control for the coal processes?

L. W. Kirsch

A. I think it's going to depend upon the particular use in which you are going to use the models. I would hope for initial control strategy that you'd be able to use very simple models, i.e., input - output models, without too much detail to the internals or what's actually happening inside the process. The reason for this is that generally one is going to be interested in the cost for doing such a thing on a CPU basis, and if one is simulating the entire process then this becomes very very expensive. Hopefully you can put the appropriate fudge factors into the model so that it does give a reasonable representation. If you are interested in more detail as to what's actually happening inside in terms of design conditions for the particular vendors, then I think you are forced to use very detailed models and consider all the specific sub-systems.

W. E. Schiesser

A. I would say in terms of our own work, we are assuming that the user of our program is comfortable with FORTRAN programming and differential equations, and that he can write down systems of such equations to describe the problem of interest. We are going to develop a series of modules for various kinds of units that will be found in a particular plant; the chances of those modules being useful directly, to some other situation, I guess is rather small. Generally, then I think the user will have to be familiar with dynamic modelling to some extent and to be able to express his models in terms of equations coded in FORTRAN programming.

A. P. Klotz

A. Basically we are using the same methodology for commercial measurement as coal gasification is; that is a purged pressure path. In the Synthoil process we have gone to a liquid purge and have used a 3/16th inch diameter process tap. The plant is not in operation so we don't have any experience on whether or not this will plug. The PDU is a rather small unit and there are very small pipe sizes involved, and we've had to go to a 1/4 inch diameter thermal well, most of these are made of Incoloy 800 because of the pressures involved. We are designed to operate at 5000 lbs. pressure, and the reactor stages operate at approximately 860 F. Incoloy is the material high for strength high resistant to corrosion. The elements are much shorter than the ones we normally use because of the errosive properties of the slurry. The coal oil slurry is 35% by weight coal. So we are going to experience a slow response time, in temperature measurements and hopefully they'll stay there long enough for a full run of the plant. As far a flow measurement goes, we've managed to stay out of the high temperature areas, and are using a multitude of modes to measure the slurry flow into the plant, we have a thermal instrument on slurry input, we have calibrated positive displacement pumps, we also have rate of weight loss on the feed tank. Between these three methods we should do a good rate of flow into the plant. All of the similar processes will experience a high pressure let down and we operate normally at 4500 lbs. to 2000 lbs. We have to get back down to atmospheric pressures for post treatment of the synthetic oil. At the present time

we're relying on a valve similar to what's used in the pilot plant, with tungsten carbide plug and seat. The flow is under the plug, which is contrary to what a lot of people who have used these let down valves. The pilot plant has had excellent experience with this type of valve and we hope to duplicate the same in the process development unit. As far as data acquisitions systems go we have put about twice as many sensing elements in the plant as well we normally would in a plant of this type. We have a data acquisition system which has been put together for us by Taylor Instrument using a varian Y-72 computer and Taylor multiplexing system and we are gathering approximately 500 points, temperature, pressure, flow, and delta P. In addition to this we are doing an extensive gas analysis on the gas waste streams. There is no reprocessing of the low pressure gas streams, those we combusted in that flare. They will be monitored with a chromatographic system and all this information will go into the data logging system. It is hoped that this will provide enough information to produce a material balance.

John Modla, Buell-Envirotech

Q. Has there been any comparison of results between mathematical modeling via computer and actual experiment on a well defined and controlled laboratory experimental set up?

W. E. Schiesser

A. No.

G. H. Quentin, EPRI

Q. Since measurement of high temperatures appears to offer extreme difficulty for use in a control system, what experience have you had in the use of "inferrential" control, that is inferring temperature (or its effects) from other measurements (such as composition)?

Chairman

There are no volunteers, so I guess we'll pass on that one.

N. L. Kautsky, Stearns-Roger

Q. When will the proceedings (including tapes of all questions and panel discussion) of this symposium be available to attendees? Will all attendees automatically receive this information or must we request same?

Chairman

A. It is automatic, and you can expect this information by December, according to Nancy O'Fallon.

A. W. Massa, C. E. Lummus-Synthane

Q. Not all instrumentation required for commercial size coal gasification plants are economically feasible for pilot plants. Vendors are welcome to propose instrumentation systems for testing and evaluation under operation conditions at pilot plants for vendor experience at less than actual total costs for prototype instrumentation.

Chairman

I understand that you are saying that vendors are free to propose solutions for testing in pilot plants or prototype demonstration plants of any system they feel is suitable for solving these problems.

O. D. Runnels, Lummus

Q. Does your program include studies or application regarding pump case materials which will withstand erosion problems inherent to coal gasification facilities?

J. L. Powell

A. Part of our program on equipment includes various pumps. Here again, all we can expect to do in this short time period is take pumps, commercial, in effect, off the shelf, try to determine their weak points, if the scroll is one, and it quite possibly is, or other parts, suggest modifications, or specify such modifications in the procurement of the pumps for the plant. Retrimming of valves, retrimming of pumps, is certainly a definite possibility and probably

a requirement in order to meet some period of operation without replacing the piece of equipment. We do have some thoughts along those lines; but we do not know which particular pieces of equipment we will be able to run through a screening test prior to putting them in the specification list, along with modifications.

1977 SYMPOSIUM ON
INSTRUMENTATION AND CONTROL
FOR
FOSSIL DEMONSTRATION PLANTS

People. . .

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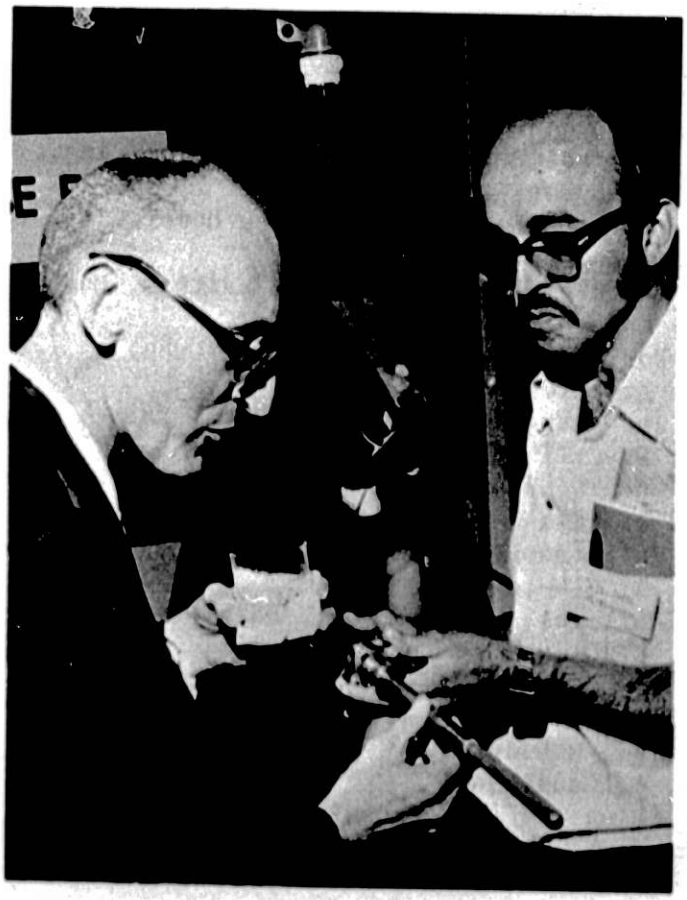
. . . to discuss. . .



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List of Attendees

A. T. Abromaitis
Bailey Meter Company, Wickliffe, Ohio
P. D. Agrawal
Procon, Inc., Des Plaines, Ill.
T. Atwood
Div. Major Facility Project Management, USERDA
D. M. Bailey
The Lummus Company, Pleasant Hills, Pa.
W. G. Bair
Institute of Gas Technology, Chicago
R. F. Batchelder
Pittsburgh Energy Research Center, USERDA
E. F. Bennett
Argonne National Lab.
R. R. Bertrand
Exxon Research & Engineering Co., Linden N.J.
T. R. Blake
Systems, Science and Software, La Jolla
F. Bondy
Foster Wheeler Energy Corp., Livingston, N.J.
D. L. Bonk
Babcock & Wilcox Research, Alliance, Ohio
D. D. Bruns
U. Tennessee, Knoxville
L. Burkhart
Ames Laboratory, Iowa State U.
C. W. Busch
Spectron Development Laboratories, Inc., Costa Mesa
J. W. Byron
Phillips Petroleum Company, Homer City, Pa.
R. Chandrasekhar
Foster-Miller Associates, Waltham, Mass.
A. Chaudhuri
Dorr-Oliver, Inc., Stamford, Conn.
R. A. Chronowski
The Mitre Corporation, McLean, Va.
D. F. Ciliberti
Westinghouse Research and Development, Pittsburgh
M. R. Cines
Phillips Petroleum Co., Bartlesville
H. A. Clayton
Phillips Petroleum Co., Bartlesville
F. L. Cleary
Bituminous Coal Research, Monroeville, Pa.
E. T. Coles
TRW, McLean, Va.
J. A. Consiglio
Solva-Tek Associates, Topsfield, Mass.
R. G. Corley
Monsanto Company, St. Louis, Mo.
D. Cornell
Mississippi State, Miss.

S. A. Cox
Argonne National Lab.
L. A. Dahm
Perkin-Elmer Corp., Tinton Falls, N.J.
L. R. Dates
Argonne National Lab.
S. Datta
Stone & Webster Engineering Corp., Boston
J. Depadro
Argonne National Lab.
R. F. Detman
C. F. Braun & Company, Alhambra
L. G. Dodge
UTRC, East Hartford, Conn.
R. W. Doering
Argonne National Lab.
A. C. Dolbec
Electric Power Research Institute, Palo Alto
C. T. Donnenworth
Lockheed-Palo Alto Research Lab., Sunnyvale
D. Dubis
Synthane Pilot Plant, Pittsburgh
D. Duffey
Argonne National Lab.
R. W. Dunlap
Environmental Research and Technology, Concord, Mass.
D. V. Dunn
Baird-Atomic, Inc., Bedford, Mass.
G. Duplantis
Gemoco Division of Chromalloy, Houma, La.
R. J. Eby
Illinois Coal Gasification Group, Chicago
J. E. Eckenrode
ARRADCOM Chemical Systems Lab., ERDA Support Office, Aberdeen Proving Ground, Md.
J. J. Eichholz
Argonne National Lab.
L. Eliason
Arthur G. McKee, Cleveland
D. F. Ellerbrock
Armco Steel Corp., Middletown
D. M. Field
Illinois Coal Gasification Group, Chicago
W. H. Fischer
Gilbert Associates, Inc., Reading, Pa.
J. W. Fitzgerald
Woodmont Associates, Ltd., Bethesda
T. Flaherty
Allis-Chalmers, West Allis, Wis.
C. R. Fleming
The Foxboro Company, Foxboro, Mass.
J. J. Forst
Div. Materials and Exploratory Research, USERDA

W. Fuchs
Pittsburgh Energy Research Center, USERDA
J. R. Gandee
Taylor Instruments, Rochester, N.Y.
T. M. Gayle
Oak Ridge National Lab.
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T. Gozani
Science Applications, Inc., Palo Alto
J. L. Gregory
TRW, McLean, Va.
W. Haas
Ames Laboratory, Iowa State U.
C. M. Hammer
Energy Research Group, Oakmont, Pa.
R. A. Hanson
Taylor Instruments, Rochester, N.Y.
P. B. Henry
Illinois Coal Gasification Group, Chicago
C. L. Herzenberg
Argonne National Lab.
A. Hirsch
Procon, Inc., Des Plaines, Ill.
T. H. Holland
Fischer & Porter Company, Warminster, Pa.
J. J. Holtgrefe
Badger Plants, Inc., Cambridge, Mass.
K. L. Hopkins
Standard Oil Company, Cleveland
J. O. Hougen
The University of Texas, Austin
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E. Huang
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Oceanography International Corp., College Station, Tex.
R. M. Hurd
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R. O. Ivins
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J. E. Janssen
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W. F. Johnson
Oak Ridge National Lab.
H. Kaplan
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N. L. Kautsky
Stearns-Roger, Inc., Denver
F. Kayihan
Oregon State U.
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Argonne National Lab.
L. N. Krause
NASA Lewis Research Center
K. G. Kreider
National Bureau of Standards, Washington
H. W. Kretsch
Consolidated Controls Corp., Bethel, Conn.
A. C. Ku
General Electric Co., Schenectady
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