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PROJECT DEEP STEAM:
FOURTH MEETING OF THE TECHNICAL ADVISORY PANEL
ALBUQUERQUE, NM, NOVEMBER 1980

R. L. FOX, A. B. DONALDSON, S. W. EISENHAWER,
C. M. HART, D. R. JOHNSON, A. J. MULAC,
J. R. WAYLAND, L. J. WEIRICK

Prepared by Sandia Laboratories, Albuquerque, New Mexico 87185
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Sandia National Laboratories

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PROCEEDINGS OF THE FOURTH MEETING OF THE PROJECT DEEP STEAM TECHNICAL ADVISORY PANEL, NOVEMBER 1980

R. L. Fox, A. B. Donaldson, S. W. Eisenhawer,
C. M. Hart, D. R. Johnson, A. J. Mulac,
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ABSTRACT

Seventeen presentations at the Fourth Project DEEP STEAM Technical Advisory Panel Meeting, held 5 and 6 November 1980 in Albuquerque, are summarized. The report concludes with Advisory Panel recommendations and a digest of the discussion that followed those recommendations.

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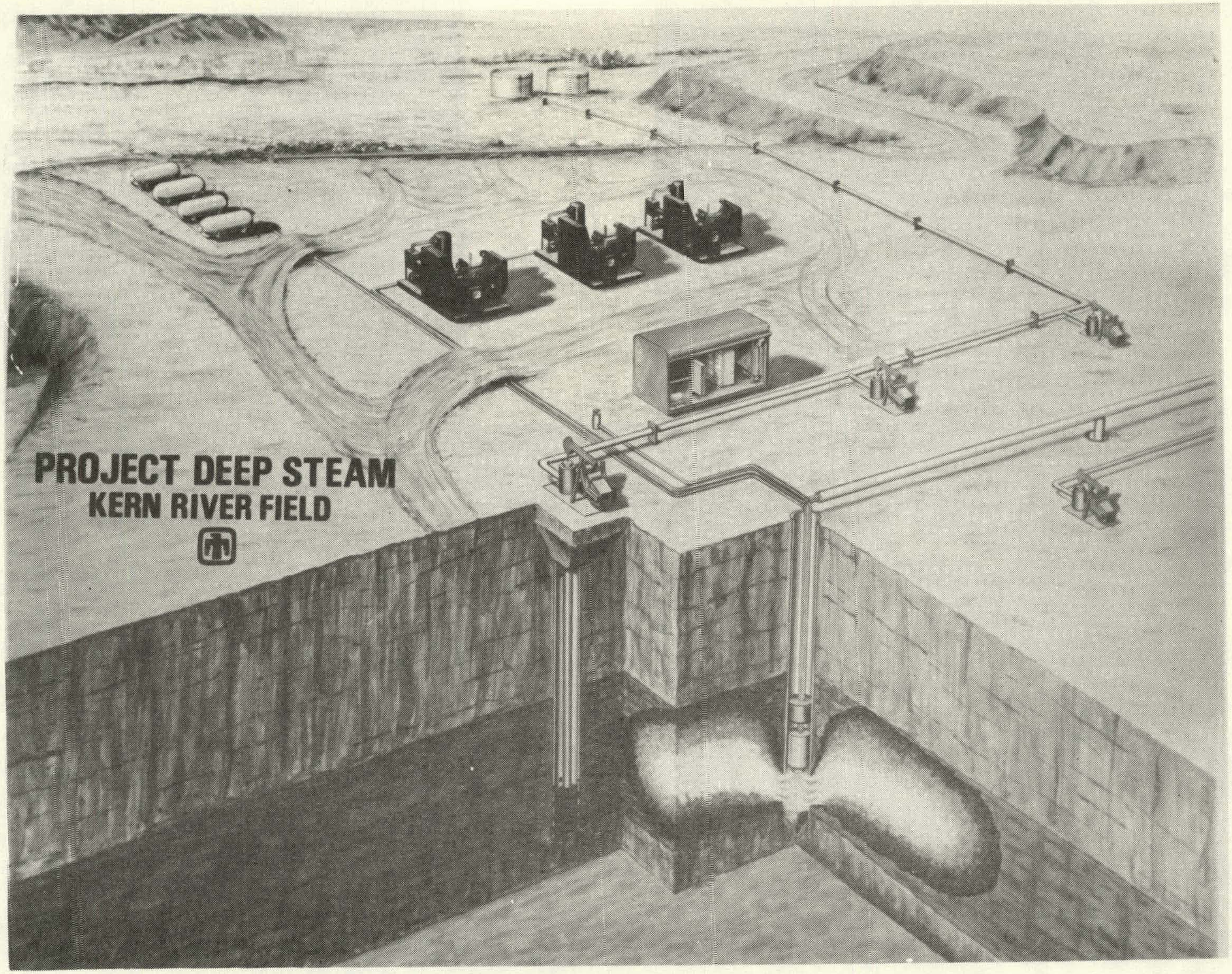

Downhole Steam Generator at the Kern River Field Test Site

FRONTISPIECE

PREFACE

The Fourth Project DEEP STEAM Technical Advisory Panel Meeting was held on 5 and 6 November 1980 in Albuquerque, New Mexico, to review the status of Project DEEP STEAM. This Proceedings, following the order of the meeting, is divided into five main sections: the injection string modification program, the downhole steam generator program, supporting activities, field testing, and the Advisory Panel recommendations and discussion. Each presentation is summarized, and a final "Discussion" section has been added, when needed, for inclusion of comments and replies related to specific presentations.

Finally, the Advisory Panel recommendations and the ensuing discussion are summarized in the closing section.

CONTENTS

INJECTION STRING MODIFICATION PROGRAM

TESTING OF THERMALLY EFFICIENT WELL COMPLETIONS

Gilbert C. Jeffery
General Electric Co.
Tacoma, Washington

The following summary describes testing of insulated well completions since the March 1980 report at the Project DEEP STEAM test facility operated by General Electric at Tacoma, Washington. The basic capabilities of the test facility for testing tubulars and packers in a 7-inch (18-cm) cemented casing are summarized in the following list.

1. Ability to test various tubulars and packers in 7-inch (18-cm) casing.
2. Test article lengths up to 60 feet (18 meters) accommodated.
3. High-pressure and high-temperature steam capability (2100 psi, 650°F (14.5 MPa, 343°C)).
4. Ability to vary soil temperature.
5. Capability to change soil characteristics.
6. Complete monitoring of data:
    - Radial temperature profile in soil
    - Casing temperatures
    - Tubing temperatures
    - Automatic recording
    - Computer reduction of large volumes of data.

These capabilities have been covered in previous reviews and are presented here for reference purposes. Figure 1 is a diagram depicting the configuration of the test stand, and Figure 2 is a cross-sectional view showing the test section, the cemented casing, the soil annulus, coolant annulus and outer tower insulation. The two tubing tests during this time period were performed on a 2-3/8-inch (5-cm) diameter Shell calcium silicate tubing and a General Electric Thermocase III

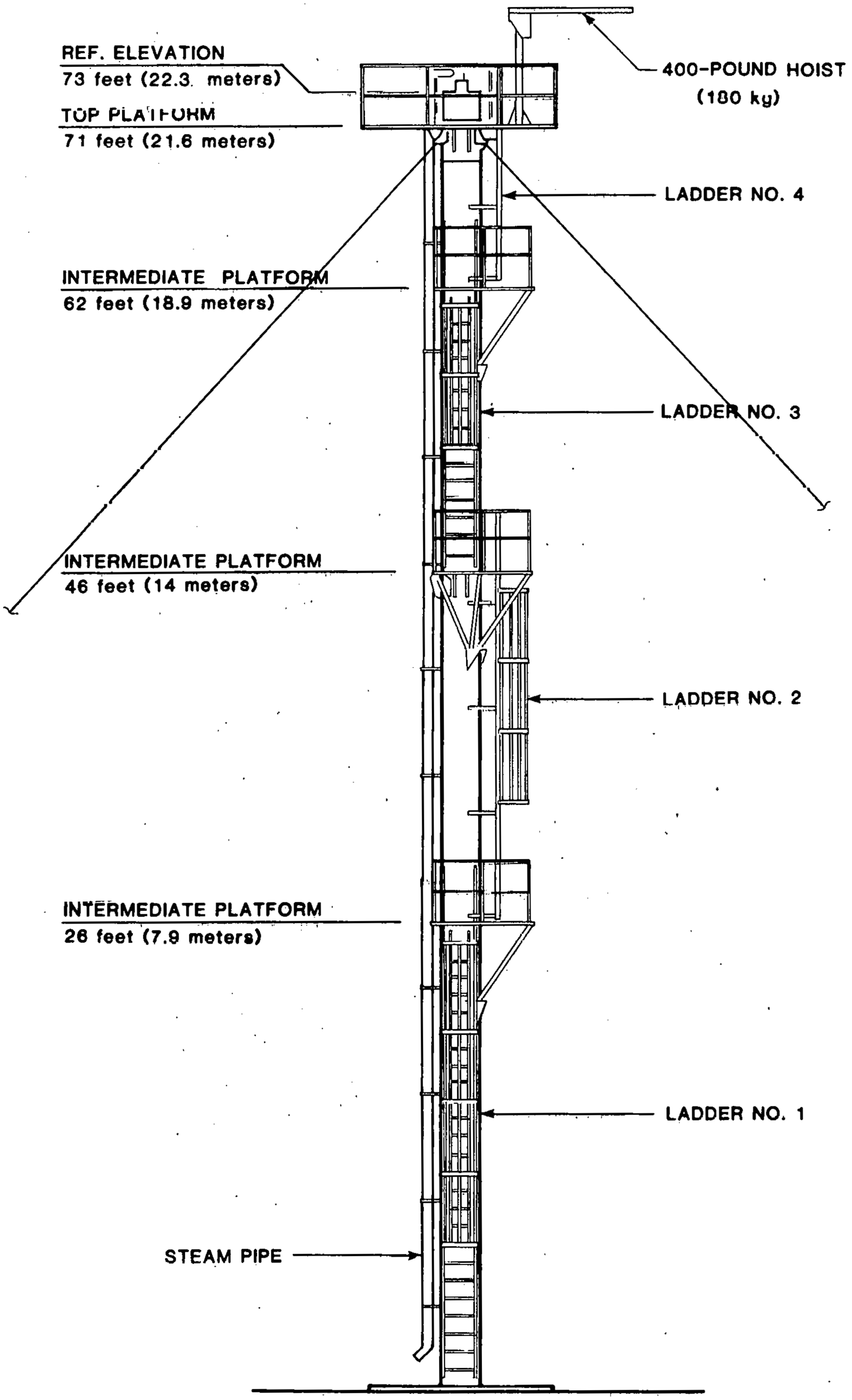

Figure 1. Test Stand for Thermally Efficient Well Completions

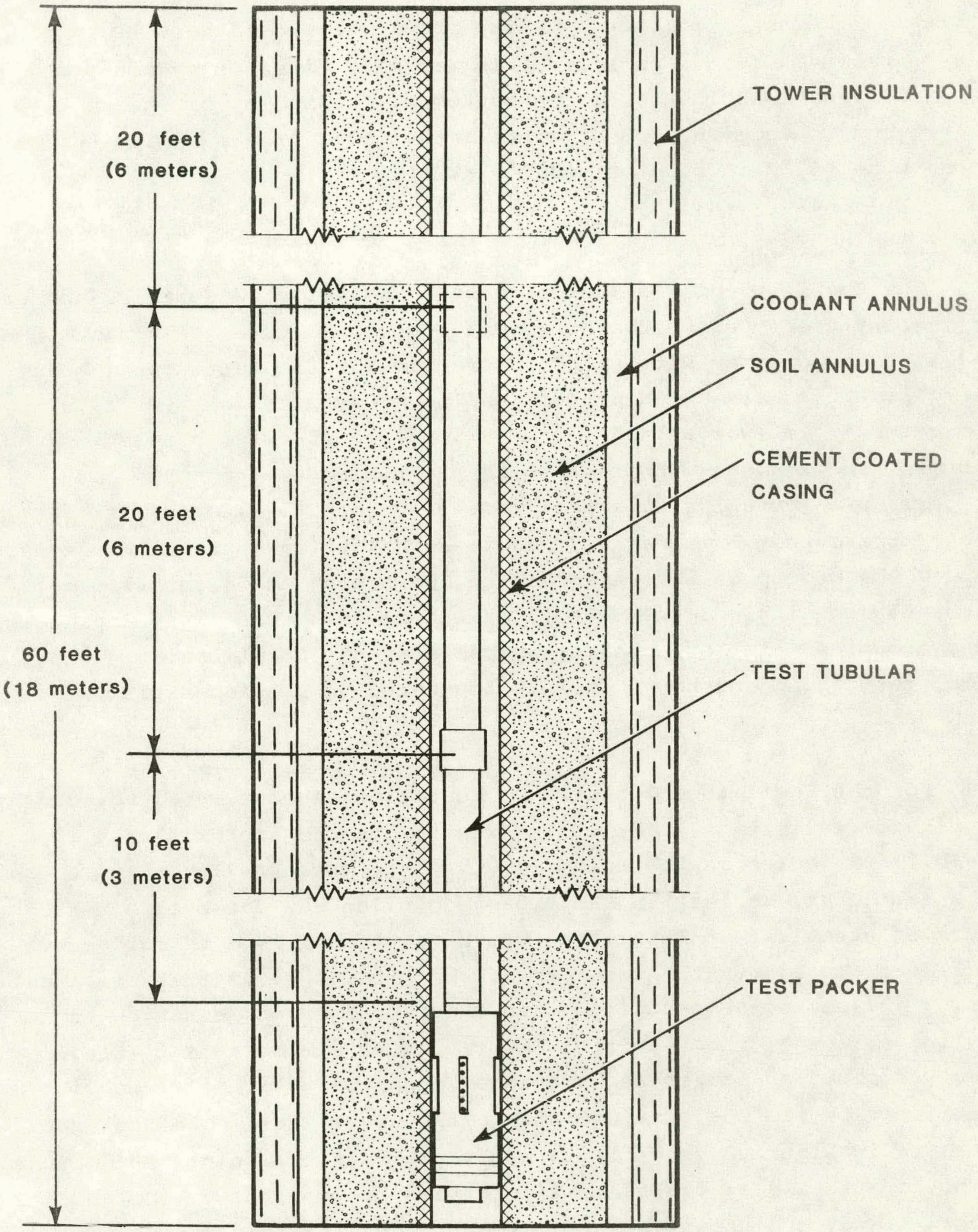

Figure 2. Test Stand Cross Section Showing Primary Components

tubing of the same diameter. Unlike previous tests, these two tests were performed without packers; this was made possible by modifying the tower and the closure of the bottom of the tubing casing annulus to prevent convection from distorting the data. The steaming conditions were 642°F at 2100 psi (339°C at 14.5 MPa).

Shell Tubing Test

The Shell tubing was manufactured by Universal Industries and had previously been used by the Husky Oil Company in five wells since 1977. In accordance with standard practice in the test tower, heat guard sections were added at each end to minimize axial heat flow. The outer jacket was welded to the 2-3/8-inch (5-cm) tubing at one end and was free to move with respect to the tubing at the other end. Spacers were installed at approximately 10-foot (3-meter) intervals, and approximately 9 inches (23 cm) at each coupling were uninsulated. Type K thermocouples were attached to the tubing at 6-foot (1.8-meter) intervals to within 3-1/2 feet (1 meter) of the tubing couplings. The thermocouples were more closely spaced near the couplings. In addition, the casing and tower were instrumented to provide radial heat flow data.

For the Shell tubing test, two heat-flow sensors were provided by Sandia for evaluation. The tubing was torqued to approximately 1200 ft•lb (1627 joules), with Husky 2000 high-temperature thread dope used as a lubricant. A leak in the tubing coupling was detected after 27 hours of steam flow. This leak, which resulted from a thread defect, increased throughout the test period, and it was noted that the local string and casing temperatures were suppressed by condensation and cooling effect of the resulting water. After 85 hours of testing, pressure could no longer be maintained, and the test was discontinued. Stabilization was not attained due to the steam leak. The test data as shown in Figure 3 shows temperature peaks at the uninsulated tubing coupling area and at the centralizers used between the tubing and its jacket. Figure 4 shows the profile of the casing temperature opposite a tubing coupling throughout the duration of the test. When the test string was disassembled, no thread galling was detected.

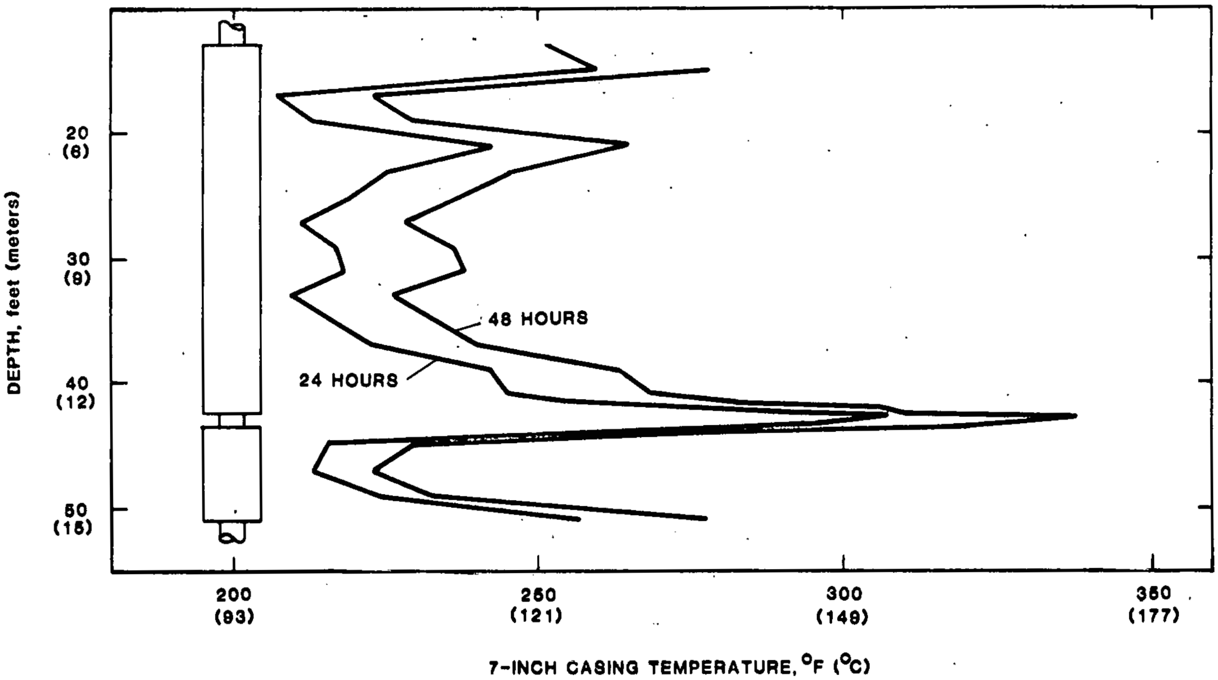

Figure 3. Shell Tubing Temperature Profile, 642°F (339°C) Steam

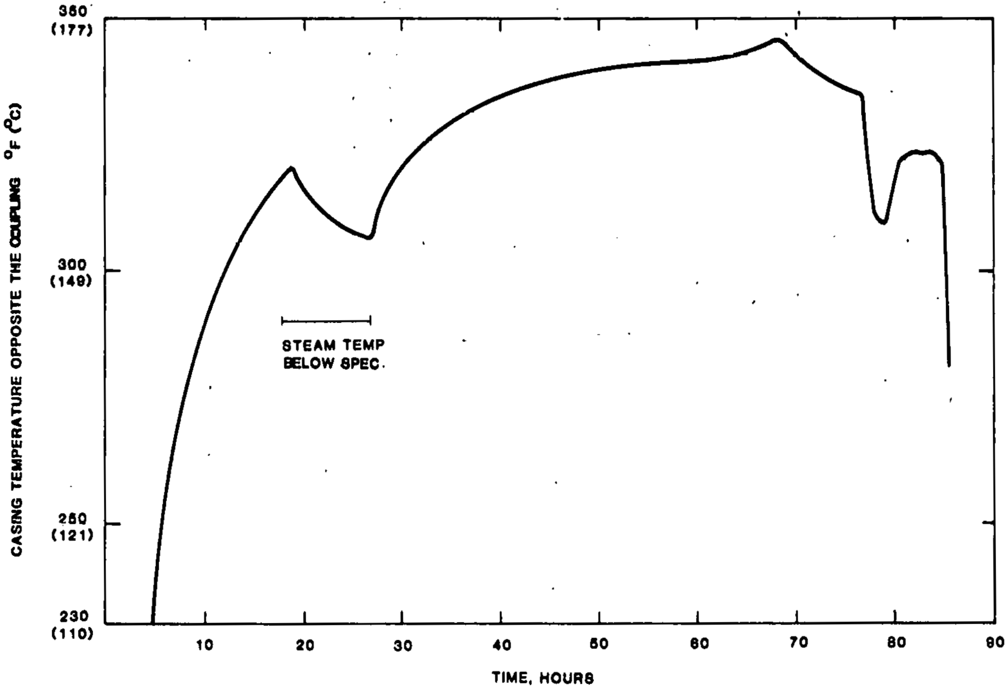

Figure 4. Profile of Casing Temperature Opposite the Uninsulated Tubing Coupling

GE Thermocase III Test

The testing of GE Thermocase III was similar to a previous test of this product except, as previously noted, there was no packer utilized and this configuration of Thermocase III included a structural support at mid-span to prevent any possible structural degradation due to packer release loads. The threads were API buttress threads, and the thread dope was Keystone Multiplex Special. Equilibrium was obtained in 9 days, and the temperatures at stabilization were similar to previous tests except for a small 285°F (141°C) hot spot in the support area.

The temperatures at stabilization are shown in Figure 5; nominal casing temperatures were 180° to 200°F (82° to 93°C). Upon disassembly of the test string, no thread galling was experienced.

Discussion

It is difficult to correlate the two tests just described since the first test did not reach stabilization and the effect of the steam leak distorted the data. Figure 6 compares the casing temperature profiles of Thermocase III and a calcium silicate test string which did not exhibit a steam leak after comparable periods of steam application.

Two obvious conclusions from the temperature profiles are that the main heat loss was in the coupling area, and that this area of high radiation extended over a large test string span (9 feet (2.7 meters) for the Thermocase III and 20 feet (6 meters) for the calcium silicate). It was also noted that in Sandia tests, calcium silicate, with its shorter exposed areas, resulted in improved thermal efficiency over previous designs tested; and that, as would be expected from the GE data, Thermocase III showed even greater increases in thermal efficiency.

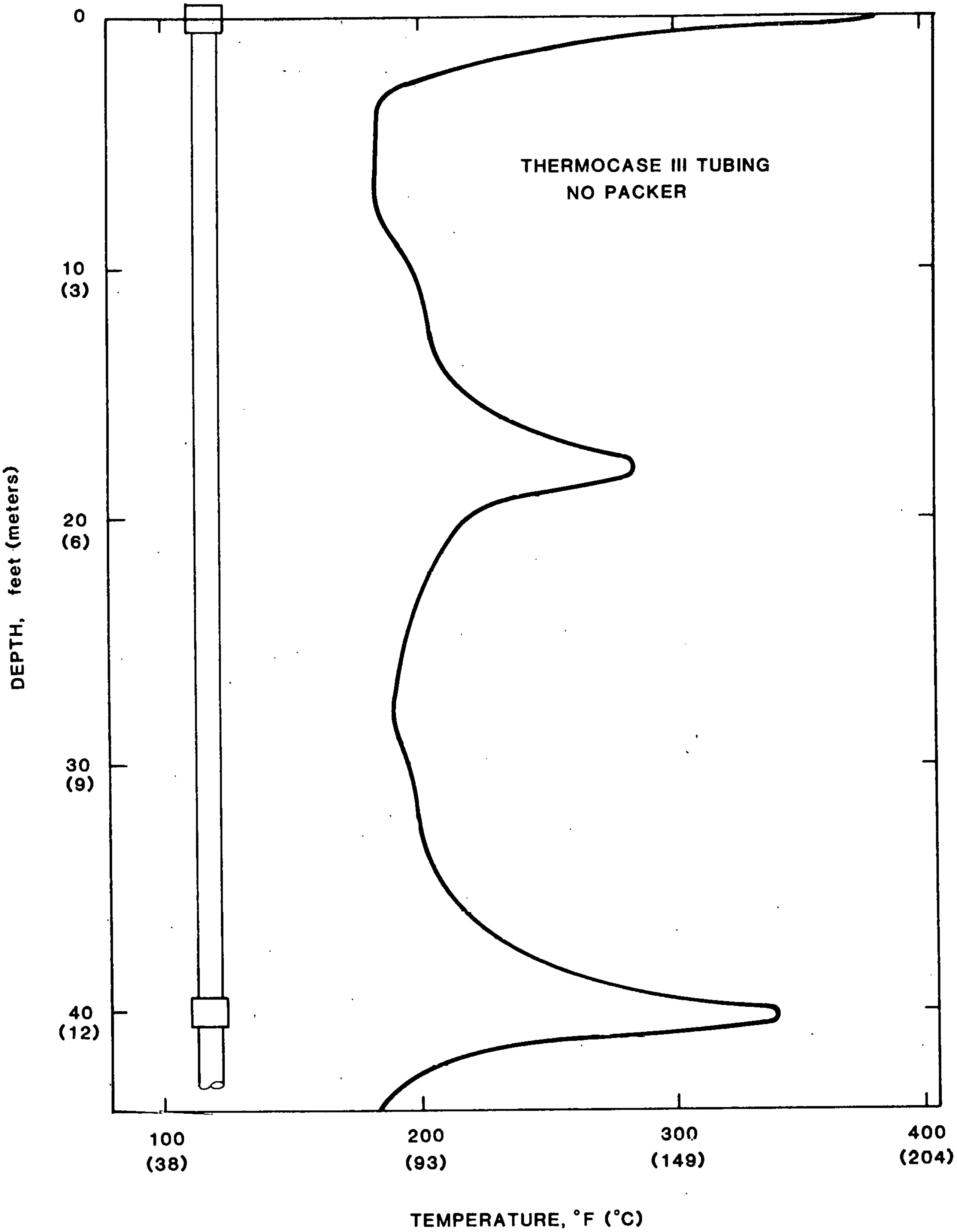

Figure 5. Thermocase III Casing Temperature Profile after 221 Hours of Operation

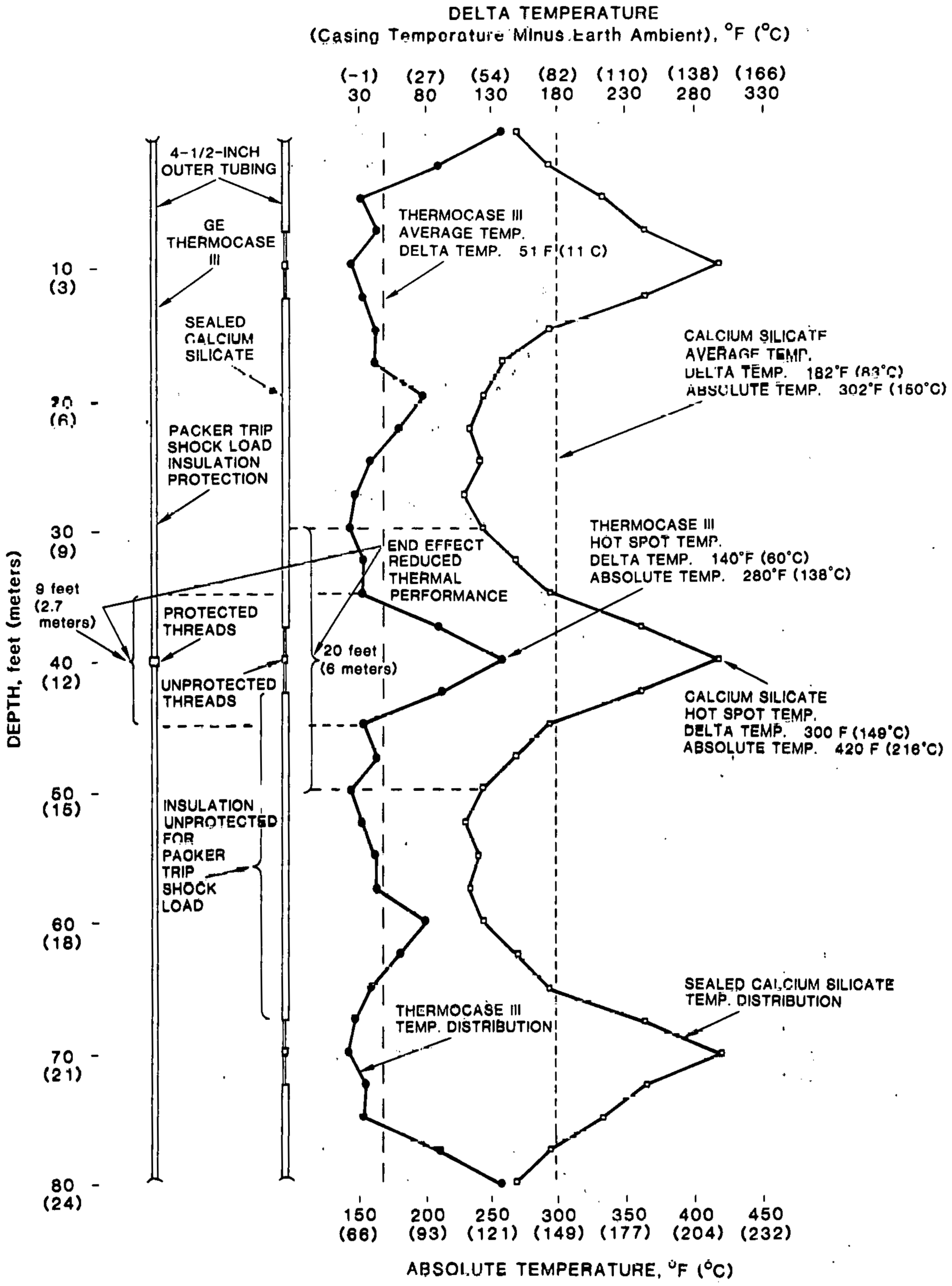

Figure 6. Temperature Profile Comparison. The Thermocase III tubing was tested for 39 hours, and the calcium silicate insulated tubing was tested for 48 hours; the earth ambient for both tests was 120°F (49°C).

INSTRUMENTATION/INSULATED TUBULAR FIELD EVALUATION

S. W. Eisenhawer
Sandia National Laboratories
Albuquerque, New Mexico

A program is currently underway at Sandia National Laboratories in cooperation with Husky Oil Operations, Ltd., to evaluate the behavior of insulated tubulars under actual field conditions. This test is being carried out at the Aberfeldy Steam Pilot near scenic Lloydminster, Saskatchewan, Canada. The goals of this program are to obtain performance data under field conditions, to compare the data with the expected performance derived from tests at General Electric, Tacoma, and predicted by the BORE code developed at Sandia.

Measurements in the test well, which is shown in Figure 1, are made at depths of 81 and 22 meters. Thermocouples are located both in and on the injection string, on the outer surface of the casing and in three thermowells attached to the casing. Heat flux sensors are also bonded to the injection string surface. Output from these sensors is acquired on a datalogger and the data is then analyzed on a computer system.

To date, testing has been performed on bare steel tubing. The well has been steamed briefly, and the installed transducers performed satisfactorily. Figure 2 charts time versus steam temperature for the bare string, and Figure 3 compares this temperature history with the casing and string temperatures.

Preparations are in progress for testing the "Shell"-design calcium silicate insulation in the near future.

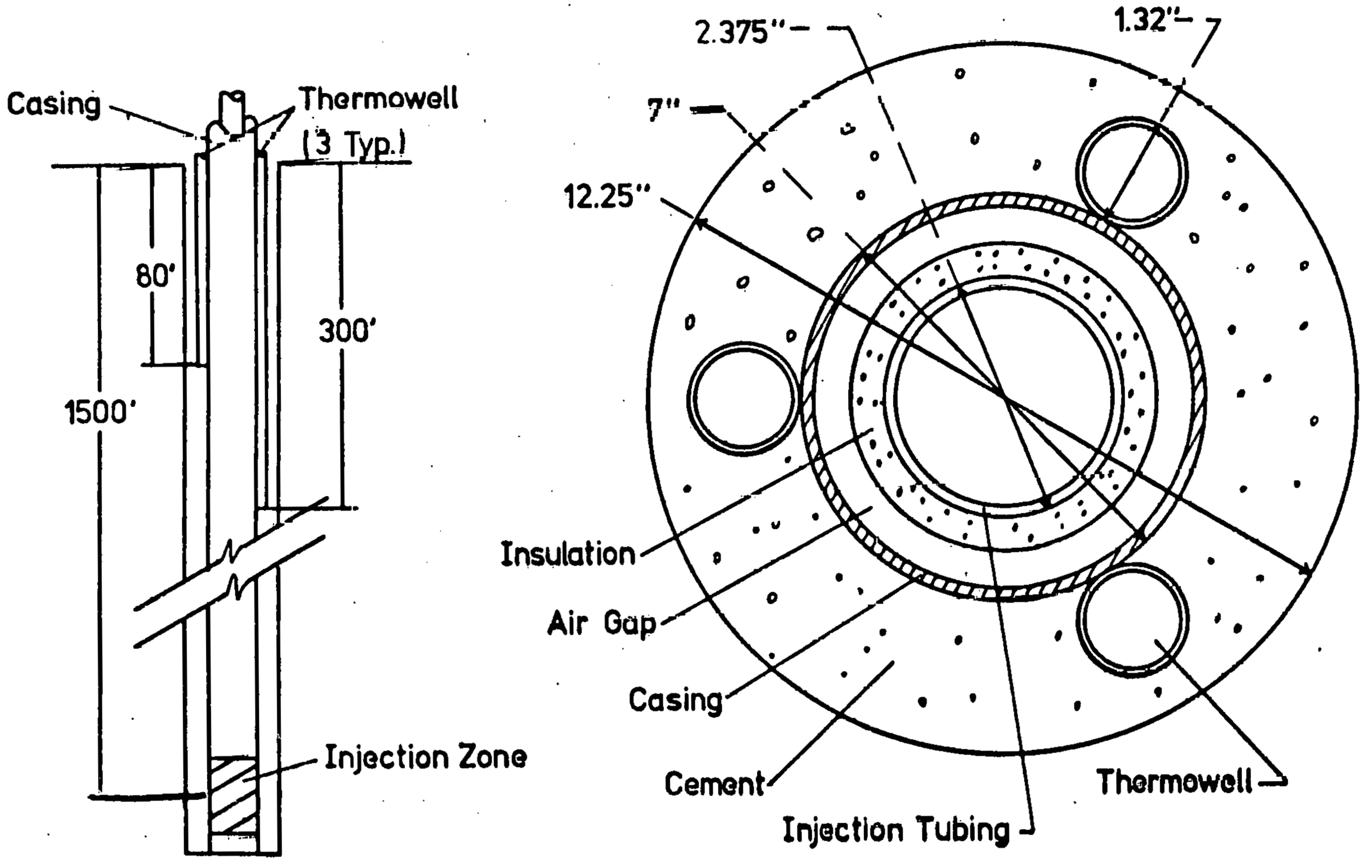

Figure 1. Test Well Profile and Cross Section

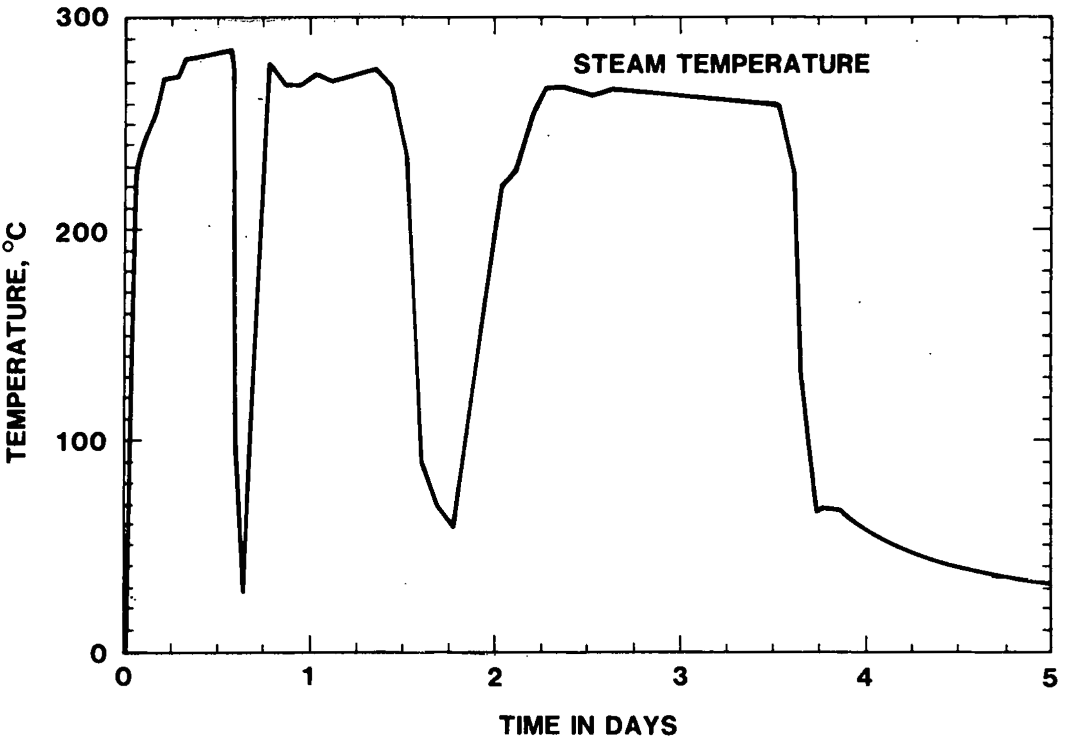

Figure 2. Steam Temperature versus Time

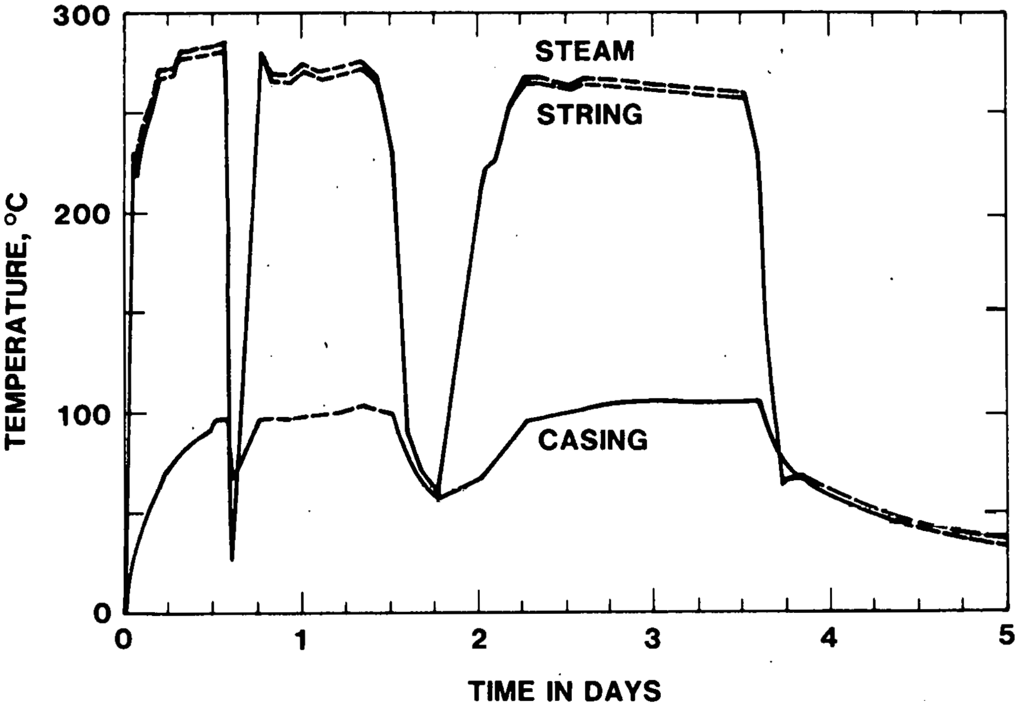

Figure 3. Steam, String, and Casing Temperatures versus Time

MIN-STRESS II PACKER CONCEPT

Alan R. Hirasuna
L'Garde, Inc.
Newport Beach, California

L'Garde, Inc., is currently developing a packer concept for the maximum DEEP STEAM requirements of 700°F (371°C) and 3000 psi (20.7 MPa). The specific packer concept is the Min-Stress II, which L'Garde conceived on private funds and proposed in response to a competitive Request for Proposal which was issued by Sandia during the Summer of 1979.

L'Garde was awarded its contract about the time of the Fall 1979 meeting of the Technical Advisory Panel. The basic contract was confined primarily to seal materials characterization, with a minor fraction devoted to the packer development. The primary effort related to the packer development is finite element structural analysis of the mechanism. All characterization measurements were performed between the Spring 1980 meeting and the current meeting.

During the summer of 1980 the scope of L'Garde's contract was increased to include design, development, and testing of a half-scale model of the Min-Stress II packer. This work, along with waiver of title of the technology by the DOE to L'Garde, will establish a sufficient base to apply for patent.

The following summary covers

- General information regarding patent aspects,
- Background of the Min-Stress design approach, and
- Advantages of the Min-Stress II concept.

Patent Aspects

Since L'Garde has a patent position on the Min-Stress II packer and since it is unclear how the rights are affected when government funds are used for development, the DOE patent policy must be clarified. The DOE and Congress strive to have government development efforts result in maximum benefit to the general economy. The more products sold which are based on its developments, the more benefit the government investment will provide the economy.

The government has been relatively unsuccessful in getting its technology utilized. A prime reason is that only nonexclusive licenses are generally offered to avoid the potential of being criticized for favoritism. Unfortunately, this policy makes the technology highly unattractive since any successes will be quickly followed by competitors who can obtain parallel nonexclusive licenses.

The DOE has taken a different tack; its general objective is to achieve more widespread utilization of its technology. Under appropriate circumstances the DOE will waive ownership of technology to the inventor, and small business is favored. This action creates a private interest that is highly motivated to see the technology to the production phase and should result in more successful commercialization of the technology.

Min-Stress Design Approach

L'Garde successfully developed elastomer compounds from four separate polymer systems for the unusually severe geothermal environment at 500°F (260°C) for 24 hours. As a part of this effort, a laboratory simulator was designed and built which tests full-scale packer seals. Evaluation of over 100 failures led to the conclusion that the primary failure mechanism with thermal packers is that the mechanical stress imposed on the seal element exceeds the strength of the material at operating temperatures. Typical seal deformation at high pressures is shown in Figure 1.

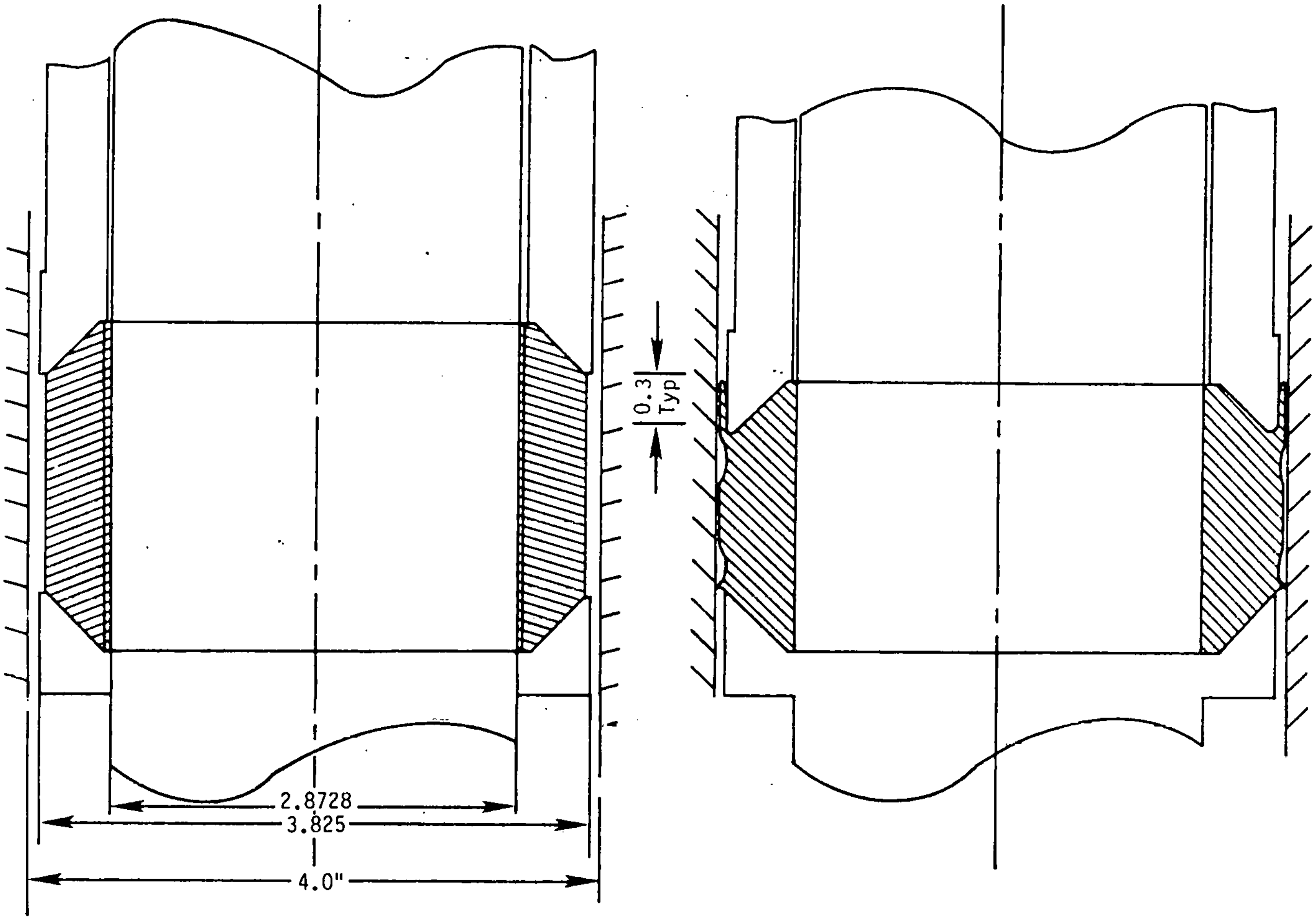

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Figure 1. Seal Deformation

It then follows that maximum temperature and pressure capability will result if the packer is designed to minimize the stress imposed on the seal element. This design approach was pursued by L'Garde and led to various mechanizations which minimize the stress in the seal.

First, an elastomeric casing packer was conceptualized as a part of the original DOE prime contract. Second, an elastomeric open-hole packer, Min-Stress I, was conceived for the geothermal environment for hydraulic stimulation, treatment, and drill-stem testing applications. Third, the Min-Stress II was conceived for Project DEEP STEAM. Min-Stress II is a steam-injection casing packer for 700°F (371°C) and

3000 psi (20.7 MPa) environments. At 700°F, the seal will be a metal; however, the packer concept will also accommodate weaker materials which are more practical at lower temperatures.

Min-Stress II Concept Advantages

The advantages of the Min-Stress II Packer are as follows:

- The Min-Stress approach
  - Yields higher pressure and temperature capability for given seal material.
  - Can accommodate broad range of materials from moderately strong metals to plastics and elastomers.
- Eliminates need for backups, i.e., stress concentrations.
- Mechanical actuation avoids thermal expansion problems associated with hydraulic fluid.
- Simple adaptation to existing packers; minimizes cost.
- No change in procedures; no special tools or equipment.
- Completely passive; set and forget.
- Anti-jamming design; springback is less than casing tolerance.

MATERIALS COMPATIBILITY*

L. J. Weirick
Sandia National Laboratories
Albuquerque, New Mexico

Twelve metals being investigated for their corrosion response in a deep steam environment were subjected to two laboratory screening tests. These metals are 1100 aluminum, 200 nickel, CP titanium, titanium SB265, 433 brass, 303Se stainless steel, 310 stainless steel, 347 stainless steel, Inconel 625, Incoloy 801, and casing alloys API N-80 and J-55. The environment for the first screening test was a simulated deep steam environment without any sulfur-bearing component. The environment consisted of 62.4% H_2O, 31.8% N_2, and 5.8% CO_2 flowing around coupon specimens contained in a furnace which was maintained at 700°F (370°C) and 1 atmosphere pressure. The specimens were exposed to this environment for 7 weeks. At 1-week intervals, the specimens were removed from the furnace, observed for appearance changes, weighed, and returned to the test environment.

With the exception of brass, all of the specimens had a bright, silver appearance when initially introduced into the test environment (Figure 1). Brass was, of course, yellow. At termination of the test, the majority of specimens exhibited an appearance change corresponding to the interference color associated with their respective tarnish film (i.e., thin, passive, protective oxide film). Thus, aluminum and nickel became a dull gray, the titanium specimens turned from silver to royal blue to light purple, the brass appeared golden,

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*This work supported by the United States Department of Energy under contract DE-AC04-76-DP00789.

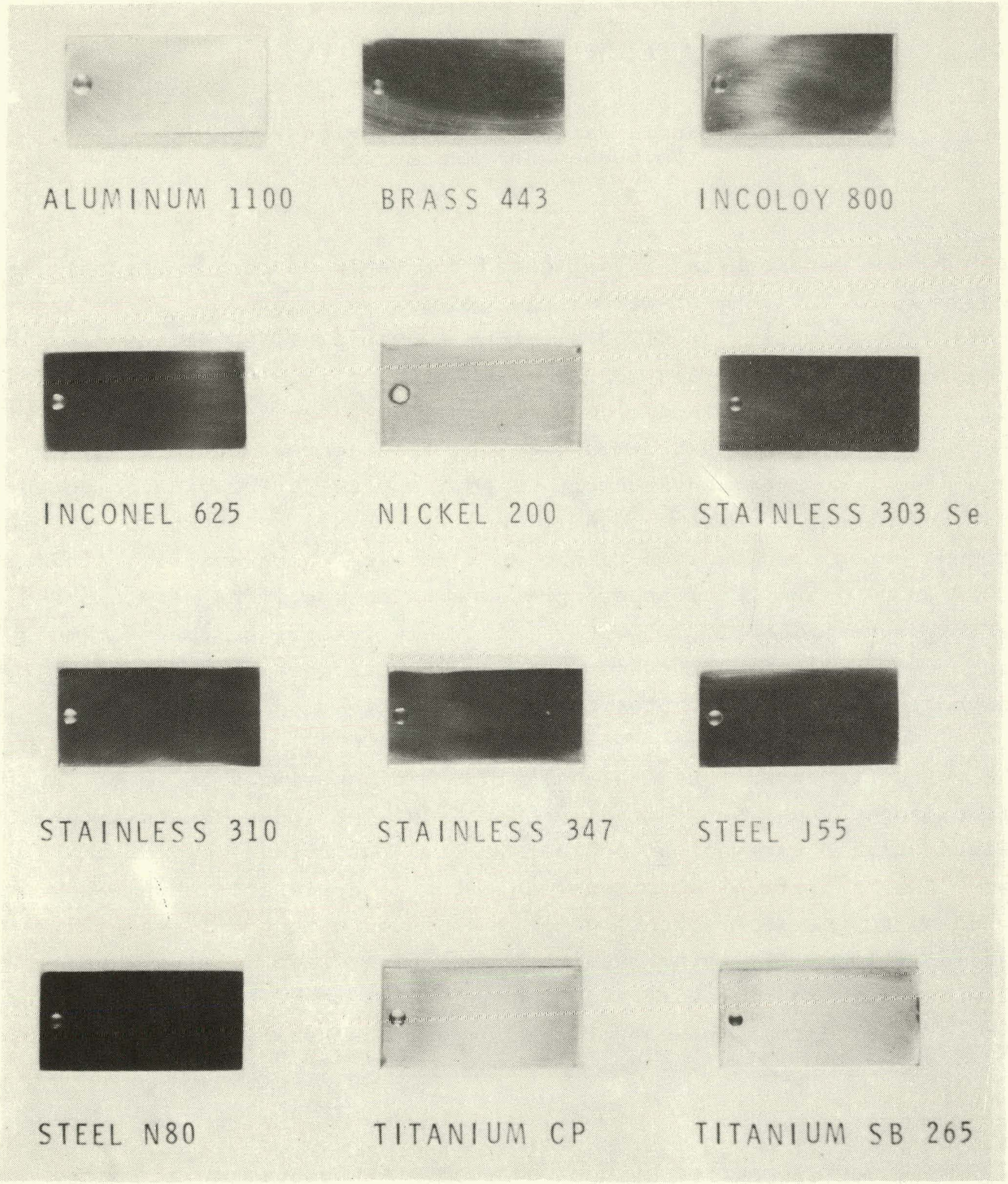


Figure 1. Samples as Prepared

and the nickel alloys and stainless steels retained their shine but became golden. Only the casing alloys N-80 and J-55, which are similar in composition to low alloy steels, changed in appearance significantly. As can be seen in Figure 2, these specimens did show signs of corrosion, including "flaking" of the iron corrosion products. The two casing materials were also the only specimens which had a significant weight change. However, this weight gain totaled only approximately 0.1% of the initial sample weight over the 7 weeks. In summarization, all of the materials tested in this set, including the casing alloys, had an acceptable corrosion response to the test environment employed.

The environment for the second screening test was a simulated deep steam environment which consisted of 62.4% H_2O, 31.8% N_2, 5.8% CO_2, and 0.0004% H_2SO_4 maintained at 700°F (370°C). The gas was passed over the coupon specimens at 1 atmosphere pressure for 9 weeks. At 1-week intervals, the specimens were removed from the furnace, observed for appearance changes, weighed, and returned to the test environment, as before.

The results from this test were similar to those of the first test. The majority of specimens exhibited an appearance change corresponding to the interference color associated with their respective tarnish film. Thus, aluminum and nickel became a dull gray, the titanium specimens turned from silver to royal blue to light purple, the brass appeared golden, the nickel alloys and stainless steels retained their shine but became golden. Only the casing alloys N-80 and J-55, which are similar in composition to low alloy steels, changed in appearance significantly. As shown in Figure 3, these specimens did show signs of corrosion, a general "rusting" of the surfaces. However, the weight gain totaled only approximately 0.1% of the initial sample weight over the nine weeks. In summary, all of the materials tested in this set, including the casing alloys, had an acceptable corrosion response to the test environment employed.

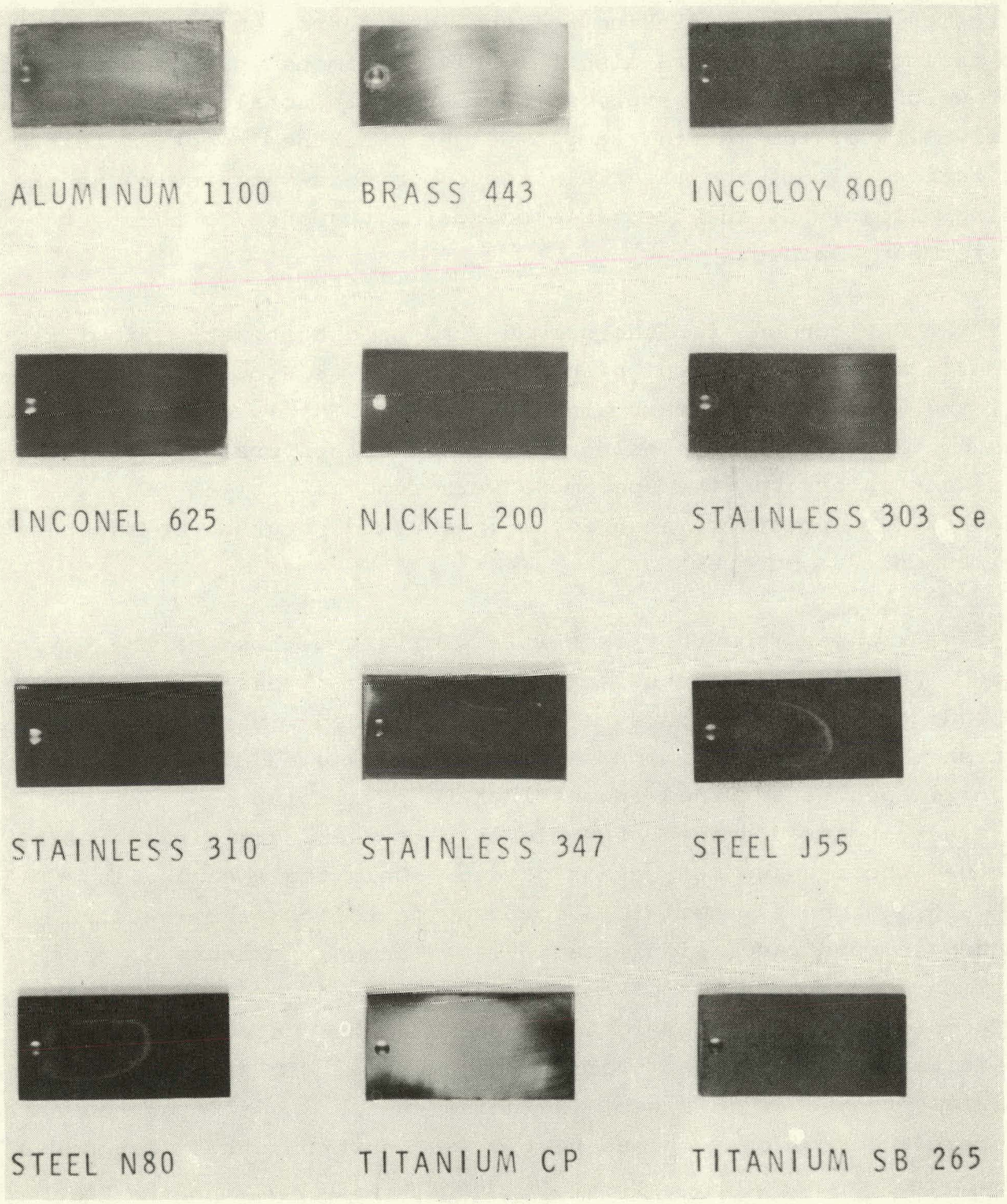
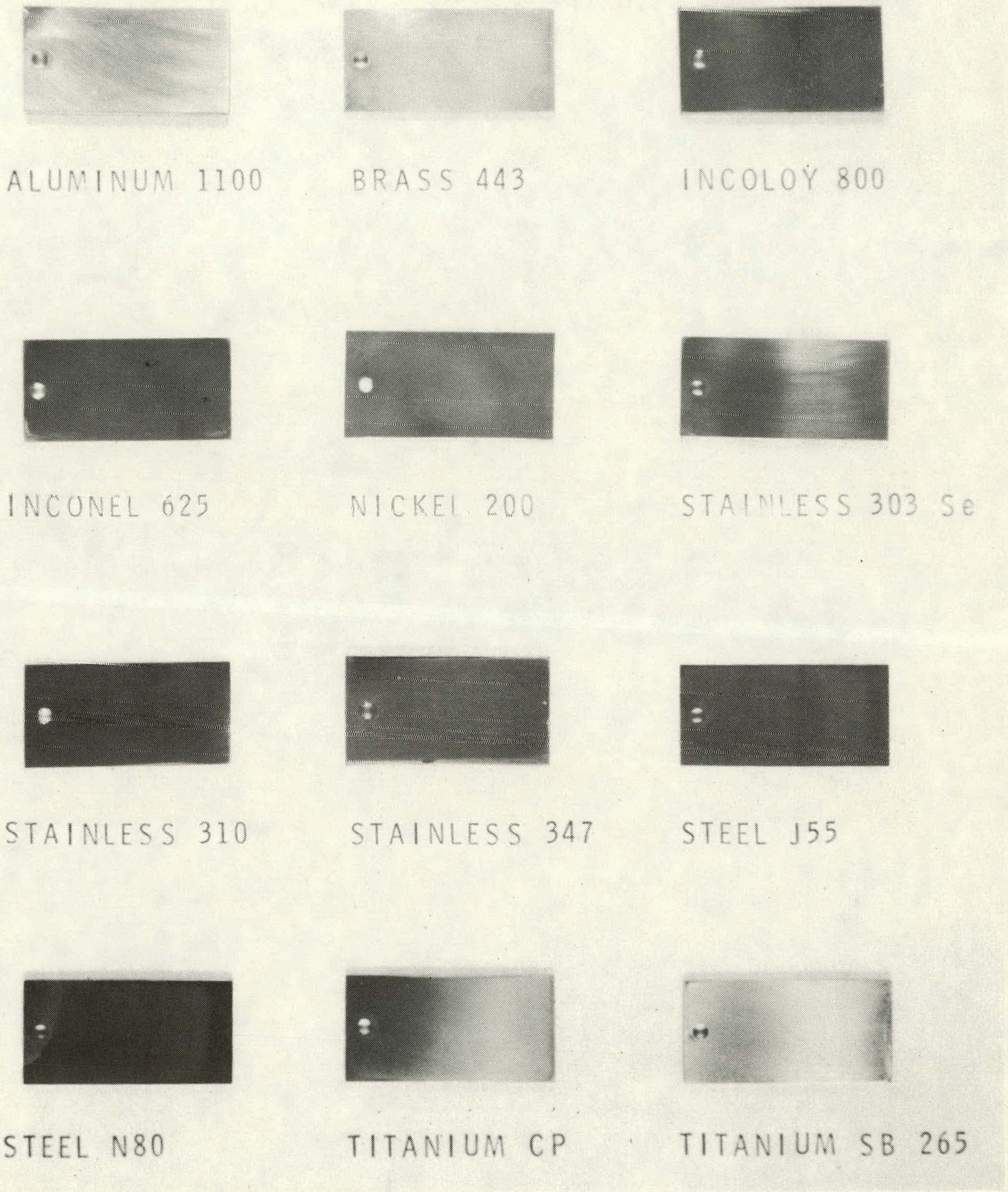


Figure 2. Samples after Exposure to 370°C Steam for 7 Weeks



ALUMINUM 1100
BRASS 443
INCOLOY 800
INCONEL 625
NICKEL 200
STAINLESS 303 Se
STAINLESS 310
STAINLESS 347
STEEL J55
STEEL N80
TITANIUM CP
TITANIUM SB 265

Figure 3. Samples after Exposure to 370°C Steam, with 10^{-4}% H_2SO_4, for 9 Weeks

DOWNHOLE STEAM GENERATOR PROGRAM

INTRODUCTION

The downhole steam generator program is directed towards developing a unit to be deployed at the bottom of an injection well to generate steam. This deployment eliminates heat losses inherent with hot delivery lines from surface steam generation. Fuel, oxidizer, and water, as well as means to ignite combustion and monitor operation, must be supplied from the surface. Various concepts have evolved for steam generation, each with advantages and disadvantages. Prominent among these are the direct contact and indirect concepts.

In the direct contact steam generator, combustion is carried out at high pressure, and water is injected into the combustion products to generate steam. An advantage of this scheme is that CO_2 solubility in reservoir oil can potentially serve to enhance sweep efficiency; a disadvantage is that higher compressor capital and operating costs are incurred. Foster-Miller Associates is conducting studies of the direct contact concept.

In the indirect concept, combustion is carried out at low pressure, and steam is generated by conduction across a heat exchanger surface. An advantage of this scheme is lower cost for delivered steam; a disadvantage is that the flue gases may need to be processed before venting. The Rocketdyne Division of Rockwell International is conducting studies of this concept.

Because combustion of heavy fuel oils at moderate to high pressures does not have a common application, fundamental studies of such processes have not been extensive. Therefore, Sandia has initiated a program of fundamental studies of liquid fuel combustion at high pressure.

Finally, because field test activities are needed to produce information on generator operations and reservoir interaction, a modest steam generator development program has been underway at Sandia.

FUNDAMENTAL LIQUID FUEL COMBUSTION STUDIES

S. A. Sheffield
M. R. Baer
G. J. Denison
Sandia National Laboratories
Albuquerque, New Mexico

Project DEEP STEAM has as one of its goals the clean burning of cheap fuels at high pressures. Fuels being considered range from crude oil to diesel fuel. A large problem arises in that this type of fuel is usually not clean burning even at atmospheric pressures. Particulate in the form of soot (from gas phase reactions) and cenospheres (the carbonaceous residue of a fuel droplet after all the volatiles have been driven off) are commonly observed. A possible solution to this problem is to design the combustion system so that secondary atomization (breakup of the droplets produced by a spray nozzle) is achieved during the burning process. This is expected to enhance the burning of both the volatiles and the carbonaceous residues.

Two methods are being investigated to produce this secondary atomization: entrainment of gases by the fuel at high pressures and emulsification of the fuel with water. In the former method, droplets are expected to be broken up as the entrained gas leaves the fuel upon depressurization of the mixture upon passing through the atomization nozzle. This method will be studied in detail later when high-pressure facilities are operational. Water-in-fuel emulsions are being carefully studied at the present time, and results of the investigation to date will be discussed.

The experimental setup consists of putting an emulsion droplet on a heated plate (~750 K) and recording the processes that occur as it vaporizes. Vaporization beneath the droplet levitates it about 10 to 50 μm above the plate. A spherical indentation in the plate contains the approximately 2-mm diameter droplet in one place so it can be easily photographed. In some of the experiments the droplet was backlighted by an expanded laser beam. In others, where the behavior inside the droplet was being recorded, the laser beam was directed to impinge on the droplet from the top, causing the droplet to light up from scattered light. High-speed pictures were taken with a Hycam framing camera.

A water-in-fuel emulsion is a mixture of water and fuel, usually with a surfactant included so that the water is the dispersed phase in a matrix of fuel. Water globules inside the fuel are a few micrometers in diameter.

Several phenomena have been observed in experiments involving 30% water/hexadecane emulsions with 2% surfactant by volume. Disruptions have been observed in which the droplet expands to about twice its volume due to vaporization of the volatiles within. An apparent skin around the drop breaks, and the droplet recoils and expels a ligament of fluid which breaks up due to instabilities. Less than 1% of the drop is lost in a disruption.

Vapor explosions of the water inside the droplet have also been observed, some heterogeneously nucleated and most homogeneously nucleated. Heterogeneously nucleated events are intermediate in violence and precipitate rather coarse fragmentation. On the other hand, homogeneously nucleated vapor explosions are of prime importance in producing secondary atomization because the drop is completely shattered by the explosion.

Information from the framing camera pictures has given us a rather clear picture of what happens to the droplet during the vaporization and vapor explosion processes. As the droplet heats up, the small water globules circulate inside the drop, circulating up around the outside and down in the center (Hill's vortex). Circulation velocities are about 0.3 m/s. As the globules circulate they bump into each other and the small globules coalesce to larger and larger globs which contort extensively as they circulate. Finally, nearly all the water coalesces to one or two globs, the circulation seems to stop and the water globs sink to the bottom of the drop since they are more dense than the fuel.

During this process the droplet temperature continuously increases finally reaching the limit of superheat for the water-oil system shortly after the water settles to the bottom. At this point the water homogeneously nucleates, usually at its lower surface since it is slightly hotter near the plate, and a rapid vaporization (vapor explosion) occurs which completely shatters the droplet. Fragment drops have velocities from 30 to 100 m/s and are estimated to have a diameter between 0.1 and 0.01 of the original drop diameter. This means that one drop is replaced by between 1000 and 1,000,000 fragment drops. Obviously these conditions would be expected to have a profound effect on the burning process.

A simple heat balance analysis has been made in which the heat required to vaporize the water (heat of vaporizaton) is assumed to come from the remaining drop, thus lowering its temperature. The results of this rough calculation indicate that the temperature of a 15% water/hexadecane drop would be reduced to 100°C if all the water were vaporized. If more water were present it would not be expected to participate in the vapor explosion. In other words about 15% water by volume is the upper limit of what would be desired in a water-in-fuel emulsion.

Other calculations have indicated that the circulation observed inside the droplet results from surface tension gradients induced by the temperature gradient in the droplet. This phenomena has been previously ignored in the combustion literature but appears to be possible in all combustion environments in which a droplet experiences an asymmetric temperature environment such as distorted flame envelopes, droplet cloud burning, etc. The authors feel this is an important observation since some of the models being used to explain multicomponent droplet burning behavior are based on the assumption that the inside of the drop is quiescent.

In summary, emulsification of fuels with water before introducing them into the hot environment of the combustion chamber is very effective in producing secondary atomization. The water globules inside the fuel matrix circulate and coalesce while the droplet heats up. When the water-oil system reaches the limit of superheat, the water homogeneously nucleates and produces a vapor explosion that shatters the droplet. An upper limit on the amount of water which participates in the vapor explosion is about 15% by volume. Although the effects of this type of behavior on the combustion process have not been measured, enhanced burning is expected which will result in cleaner combustion products.

HIGH-PRESSURE COMBUSTION STEAM GENERATOR

K. Captain
Foster-Miller Associates
Waltham, Massachusetts

Primary emphasis has been directed toward testing the steam generator at combustion pressures in the range of 200 to 300 psi (1.4 to 2.1 MPa). Analyses of typical exhaust gas temperature, percent free O_2 and CO_2, and ppm of CO in the exhaust are shown in Figure 1.

Development of an improved ceramic liner design was also begun. Figure 2 shows three basic concepts being evaluated. The liner and support structure have been designed to limit the inner wall temperature to about 3000°F (1650°C) and to reduce inner and outer wall stresses during startup (thermal shock) to a level below the failure limit of the ceramic. A combination of computer simulation and testing has just begun in order to develop a rugged design suitable for prolonged operation in the field.

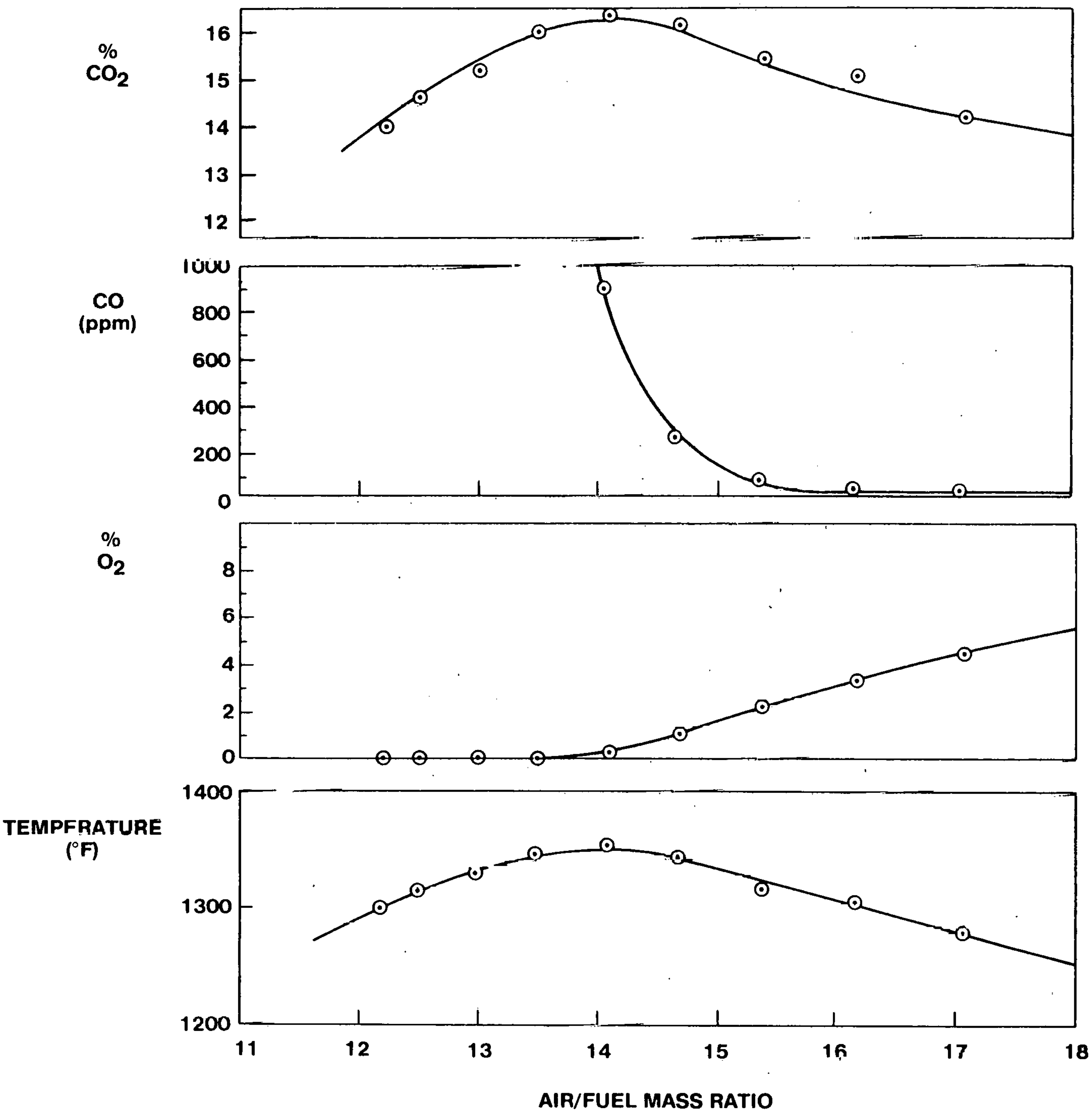


Figure 1. Analysis of Typical Exhaust Gas

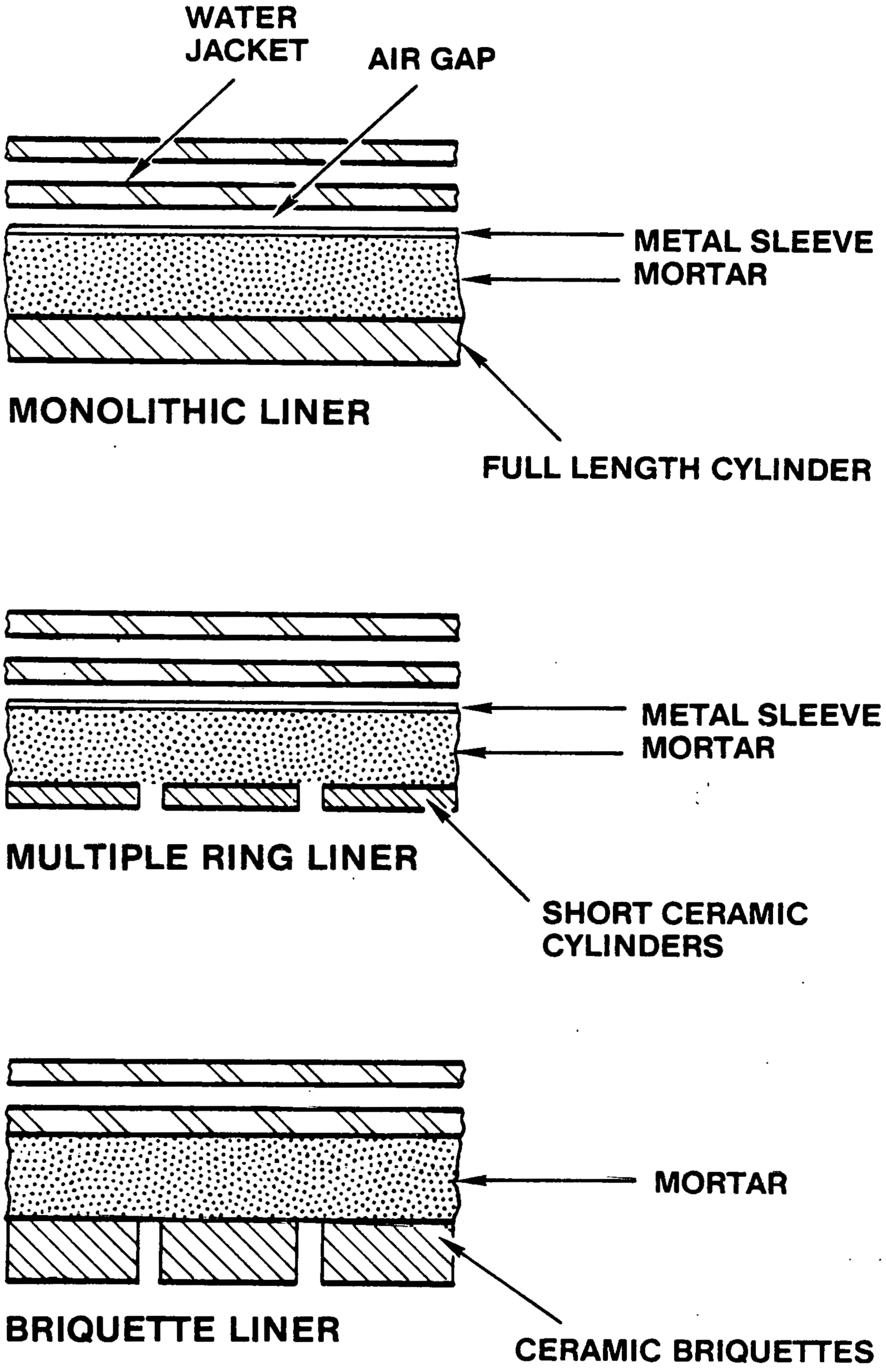


Figure 2. Improved Liner Concepts

INDIRECT DOWNHOLE STEAM GENERATOR

David Wright
Robert Binsley
Rockwell International, Rocketdyne Division
Canoga Park, California

Rocketdyne's work on Project DEEP STEAM began in late September 1978. The ultimate objective of this contract was development of a steam generator capable of generating steam at depths greater than 2500 feet (762 meters) for economical recovery of heavy crude oils. The intent was to show, by adequate analysis and laboratory testing, that the selected low-pressure combustion, indirect heat transfer concept for downhole steam generation was commercially feasible.

Initial effort on the contract involved comparing a large number of system approaches to downhole steam generation and selecting the most economical of these. The low-pressure combustion system was selected as most economical, with exhaust gas scrubbing not included. Parametric analysis of this indirect system and construction of a feasibility test unit followed. The primary effort on the contract recently (when funding has been available) has been testing of the feasibility unit.

The test setup is shown in Figures 1 and 2, and the kinds of tests which have been run on the feasibility test unit are summarized in Table 1. The hydrogen combustion wave igniter approach to igniting a pilot jet has been exercised over 500 times. All of these were remote ignitions through approximately 500 feet (152 meters) of piping. Over 400 ignitions of the main combustor using No. 2 fuel oil as the fuel, and the hydrogen pilot jet as the ignition source, have also been demonstrated.

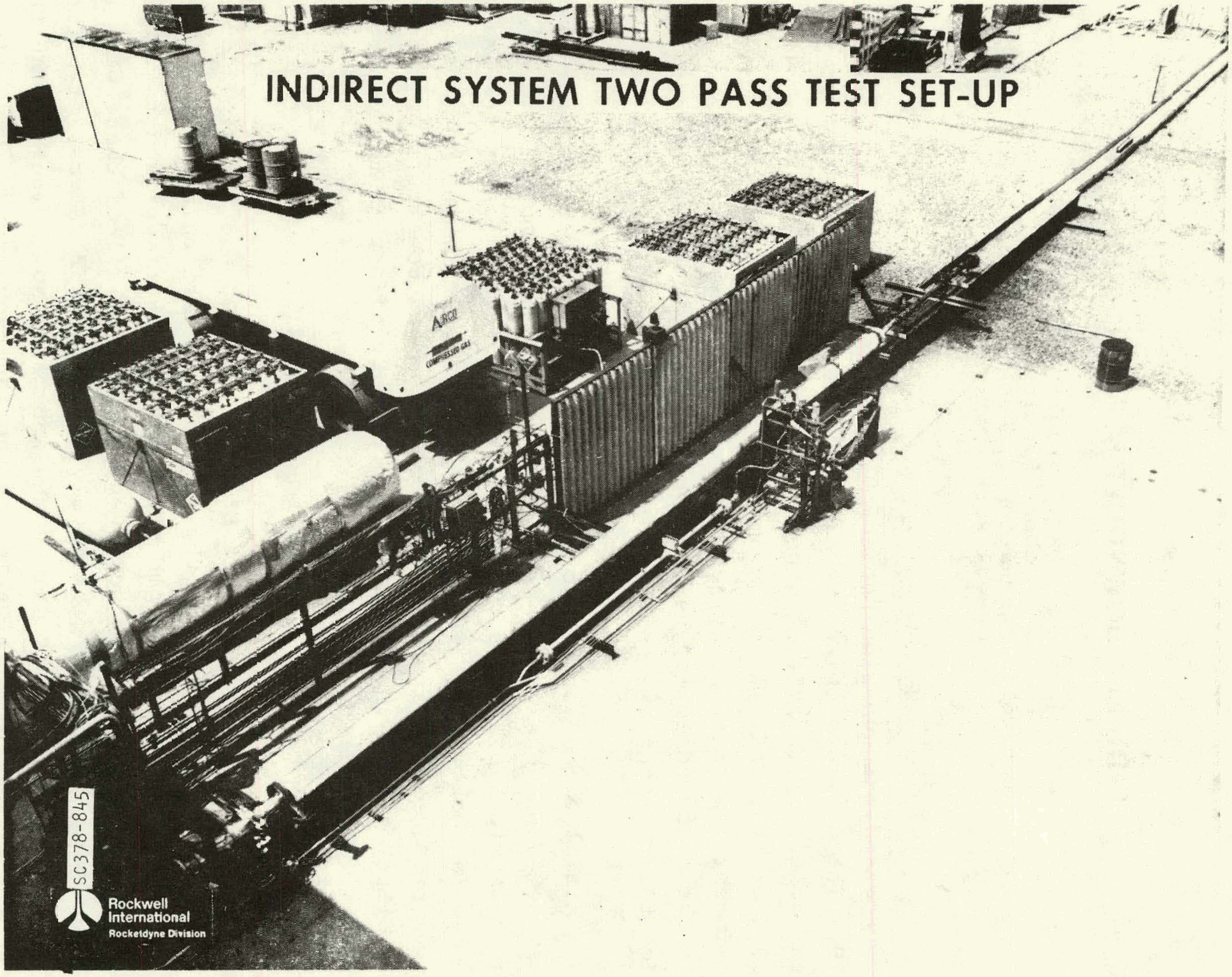


Figure 1. Test Setup for Two-Pass Indirect Downhole Steam Generator

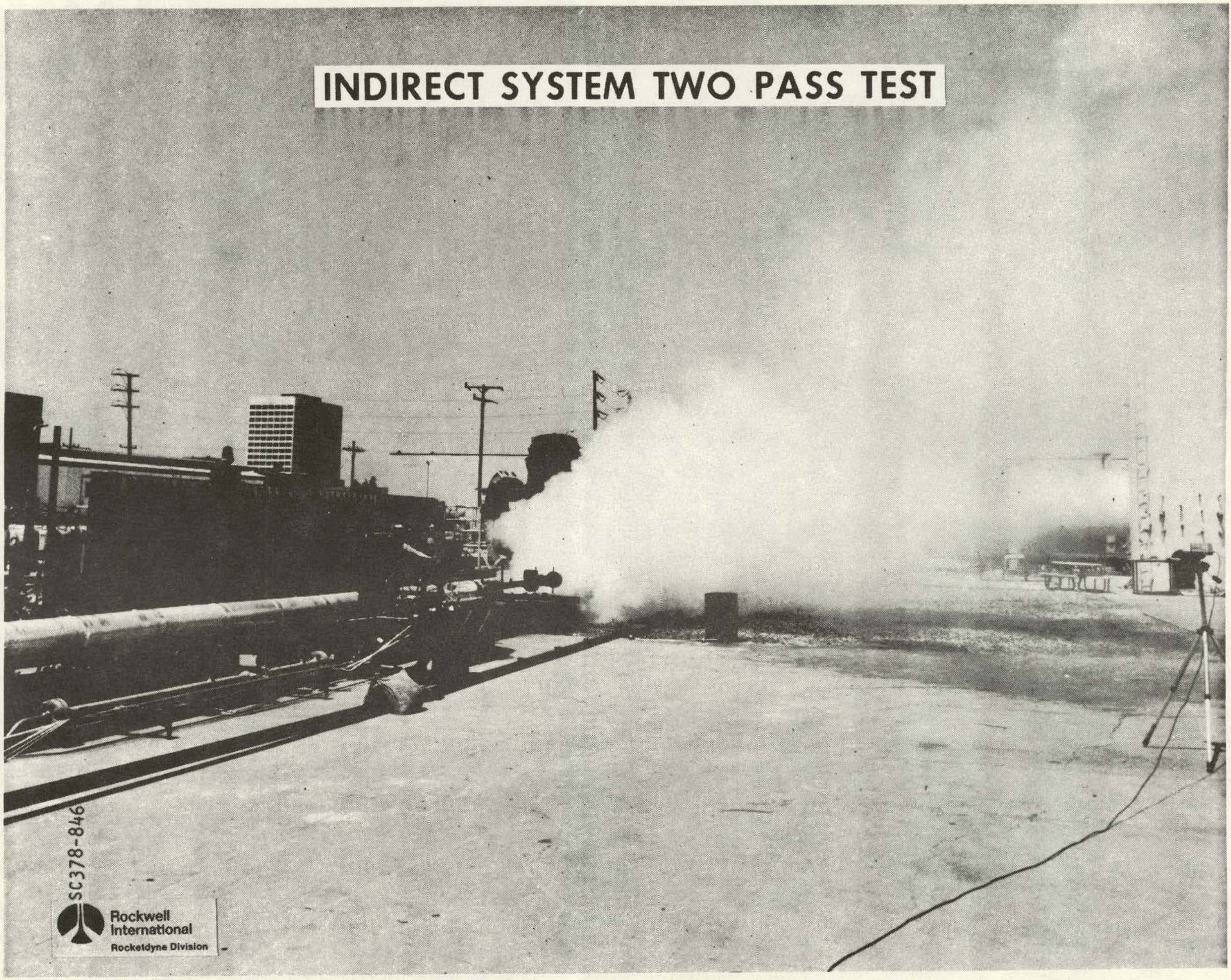


Figure 2. Test in Progress

Table 1

Summary of Testing (to 9/26/80), Indirect Downhole Steam Generator

Remote Ignitions	Number of Tests	
Of pilot	540	
Of main combustor	408	
Steam Generator:	**Single Pass**	**Two Pass**
Heat flux	9	5
Combustion limits	23	3
Steam generation	47	15
Water stability		25

Steam generator testing has been conducted in both the single-pass and two-pass configurations: these refer to the number of gas side passes, as illustrated schematically in Figure 3. The unit was tested first in the single-pass configuration, then the two-pass.

Heat flux tests were those run under steady-state conditions with high water flows such that no boiling took place. Heat flux can be measured under these conditions by water temperature rise. Combustion limits testing included exploring both flowrate and mixture ratio upper and lower limits. Steam generation runs, of course, were those where steam was generated. The water stability runs were special tests to investigate the effects of upstream pressure drop on stability of the system when boiling is taking place.

Some additional data reduction has also recently been done on the program. This is based on a model which includes water side convection, tube wall resistance, carbon layer resistance, and gas side convection. For a non-boiling case, the input data is water flowrate and temperature, hot gas flowrate, and exit temperature and pressure. The model will iteratively solve for the combustion temperature and carbon layer resistance which cause the calculated heat flux and temperatures to match the measured heat flux and temperatures. Some

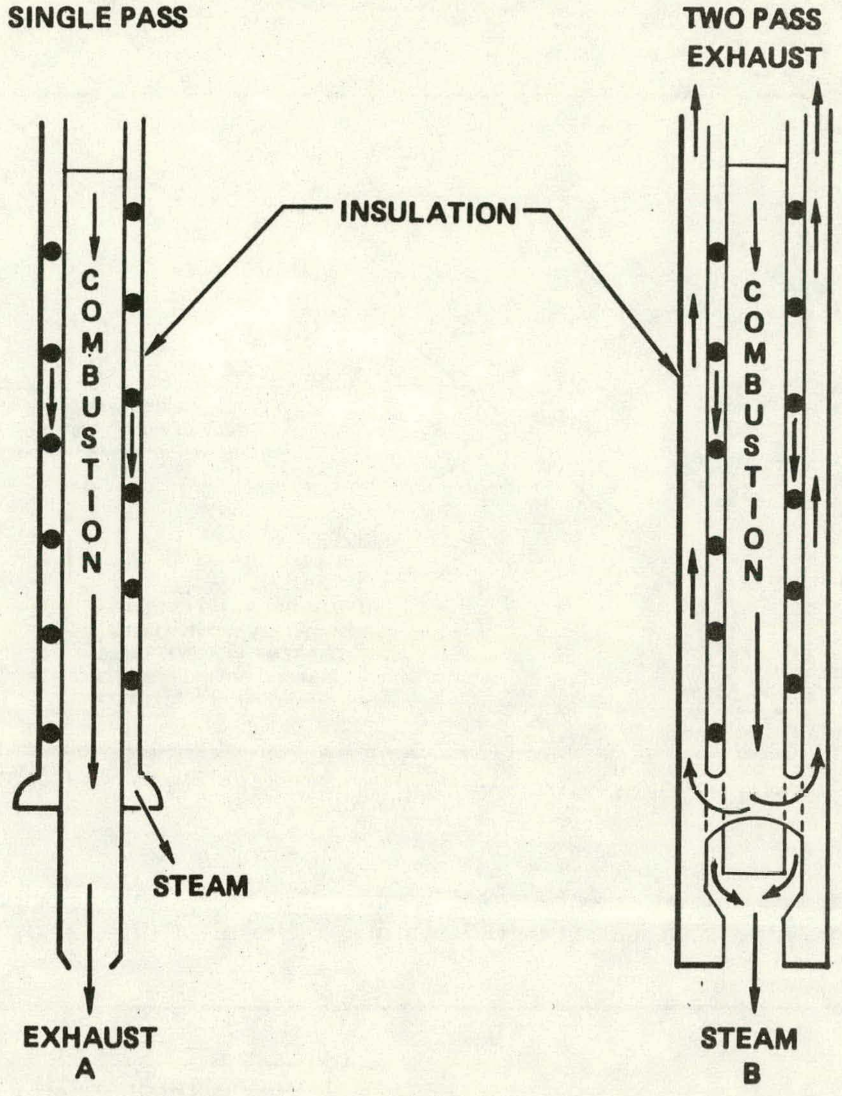


Figure 3. Gas Flow in Single-Pass and Two-Pass Concepts

of the results of the calculations are shown in Figures 4 and 5. Figure 4 compares the calculated water temperature as a function of distance to the measured water temperature; the agreement is quite good. In Figure 5, the combustion temperature is plotted as a function of air fuel ratio. The solid line represents the temperature calculated by thermochemical means from the fuel and air properties. The circles represent combustion temperature calculated from the experimental data using the model. Again, the agreement is quite good, indicating a high combustion efficiency.

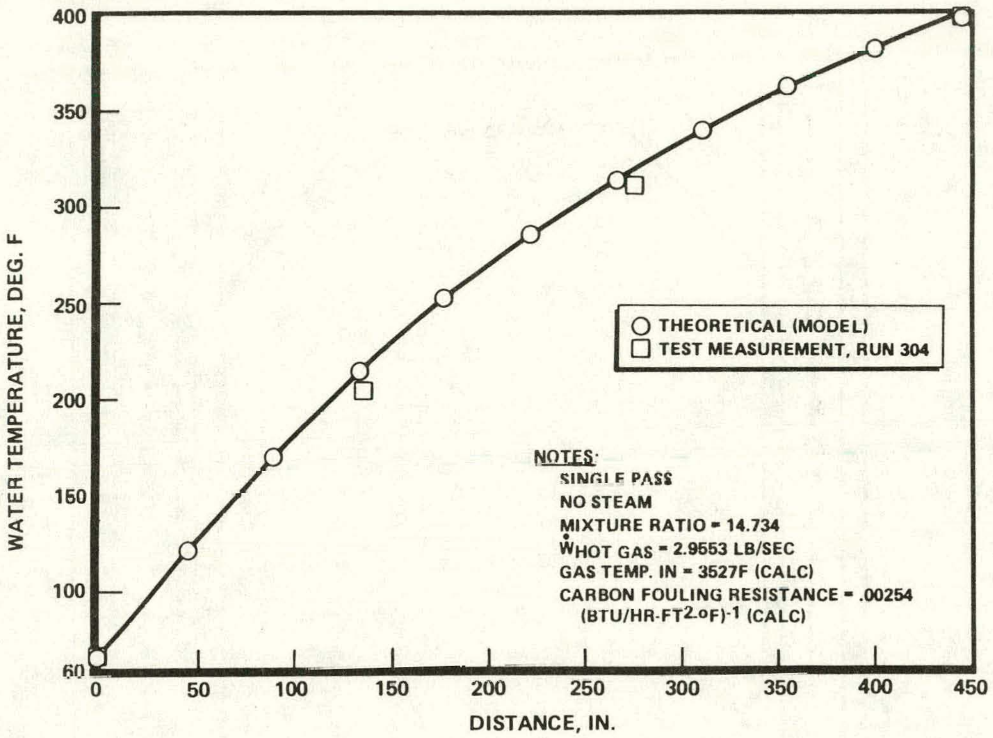


Figure 4. Heat Exchanger Water Temperature Comparison for Indirect Downhole Steam Generator

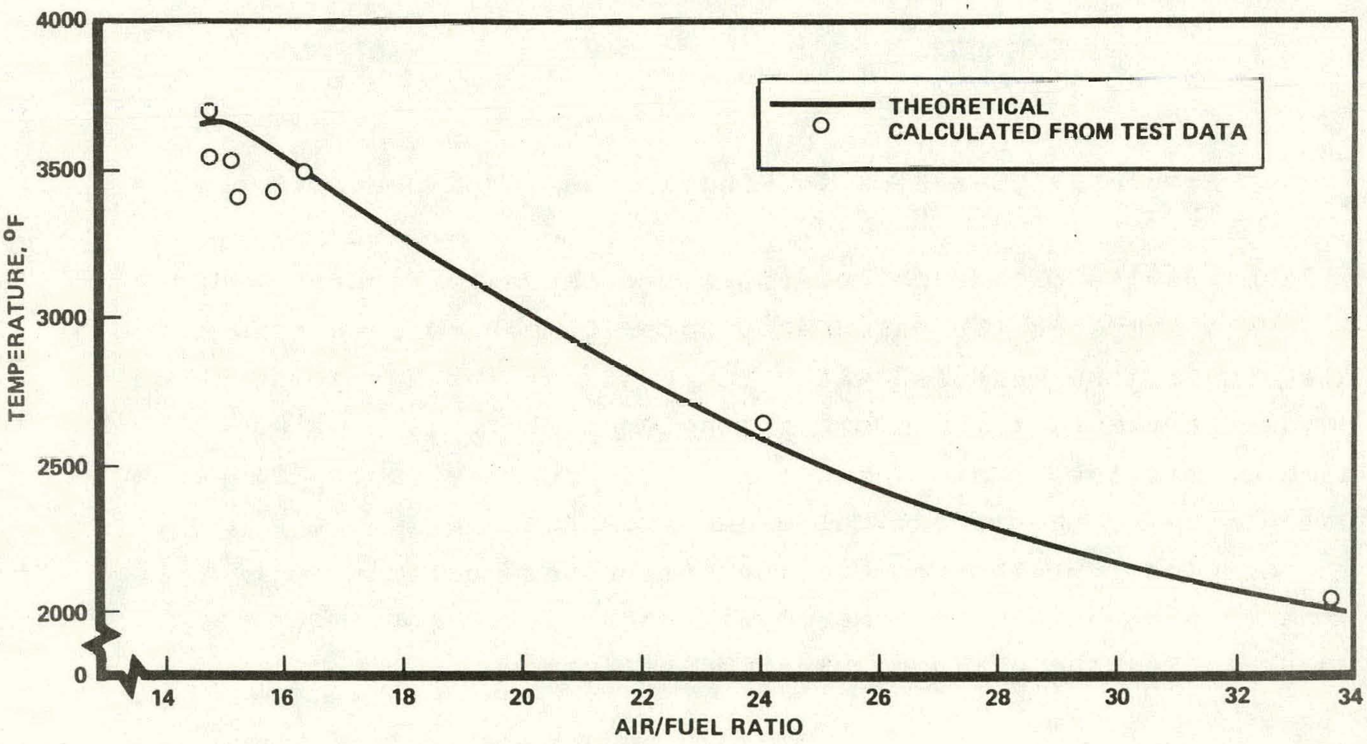


Figure 5. Combustion Temperature Comparison

The effect of having a second pass on the heat exchanger is shown in Figure 6. The parameter on the ordinate, the rationalized heat transfer, assumes that the gas side convection is the limiting factor in heat transfer. Thus, data at different heat flowrates and gas flowrates can be placed on a common basis by means of this parameter. The heat transfer is increased approximately 25% by the addition of the second pass. This is compatible with what is predicted for this

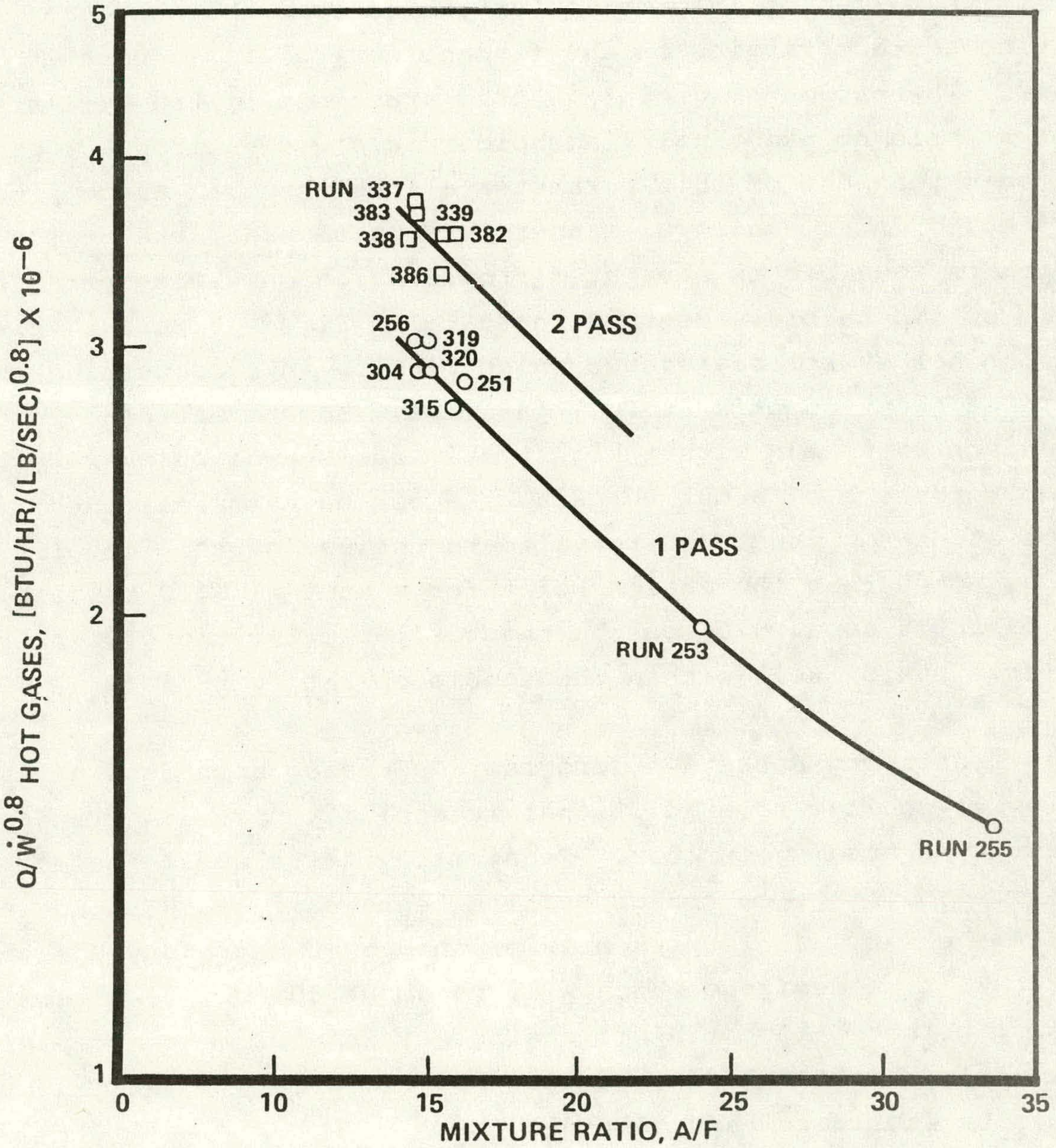


Figure 6. Rationalized Heat Exchanger Data Showing Effect of a Second Pass

specific configuration. It should be noted that the second pass, as tested, was not an optimum design; that is, the velocities, and hence the heat transfer, were low. An optimum design would show even more effect of the addition of the second pass. Since the heat transfer area required is inversely proportional to the rationalized heat flow parameter, it is clear that addition of a second pass reduces the required area and, therefore, the required heat exchanger length, significantly.

One other kind of information extracted from the test data is the combustion characteristics of the flameholder. This is plotted in Figure 7. The parameter groupings used are those of the well-stirred reactor. While no practical flameholder is a well-stirred reactor, it can be seen that use of this parameter allows the data to be processed and presented in a meaningful manner. In particular, the region where operation is feasible is separated from the region where operation is marginal or impossible. Most of the data in Figure 7 were obtained with a nominal system resistance which results in a combustion chamber pressure of about 65 psia at full gas flow. Some additional tests were inadvertently run with a high system resistance which resulted in a maximum pressure of about 90 psia. As can be seen, all these data are consistent and thus tend to validate the use of this model. It should be noted that the design point for a nominal 1000 barrels/day system falls at about 0.05 on the reactor parameter and 0.95 on the equivalence ratio, well within the stable operating region.

The continuing Rocketdyne program, depending upon funding availability, will include some additional feasibility unit tests and work on a prototype steam generator. Feasibility tests would include exhaust gas sampling, carbon deposition tests, and tests of an inner swirl flameholder. It is presently planned that a prototype steam generator will be designed which will be about 30 feet (9 meters) long and will fit in a 7-inch (18-cm) casing. This will have a capacity of approximately 300 barrels/day at 1500 psi (10.3 MPa). The generator will then be fabricated and tested.

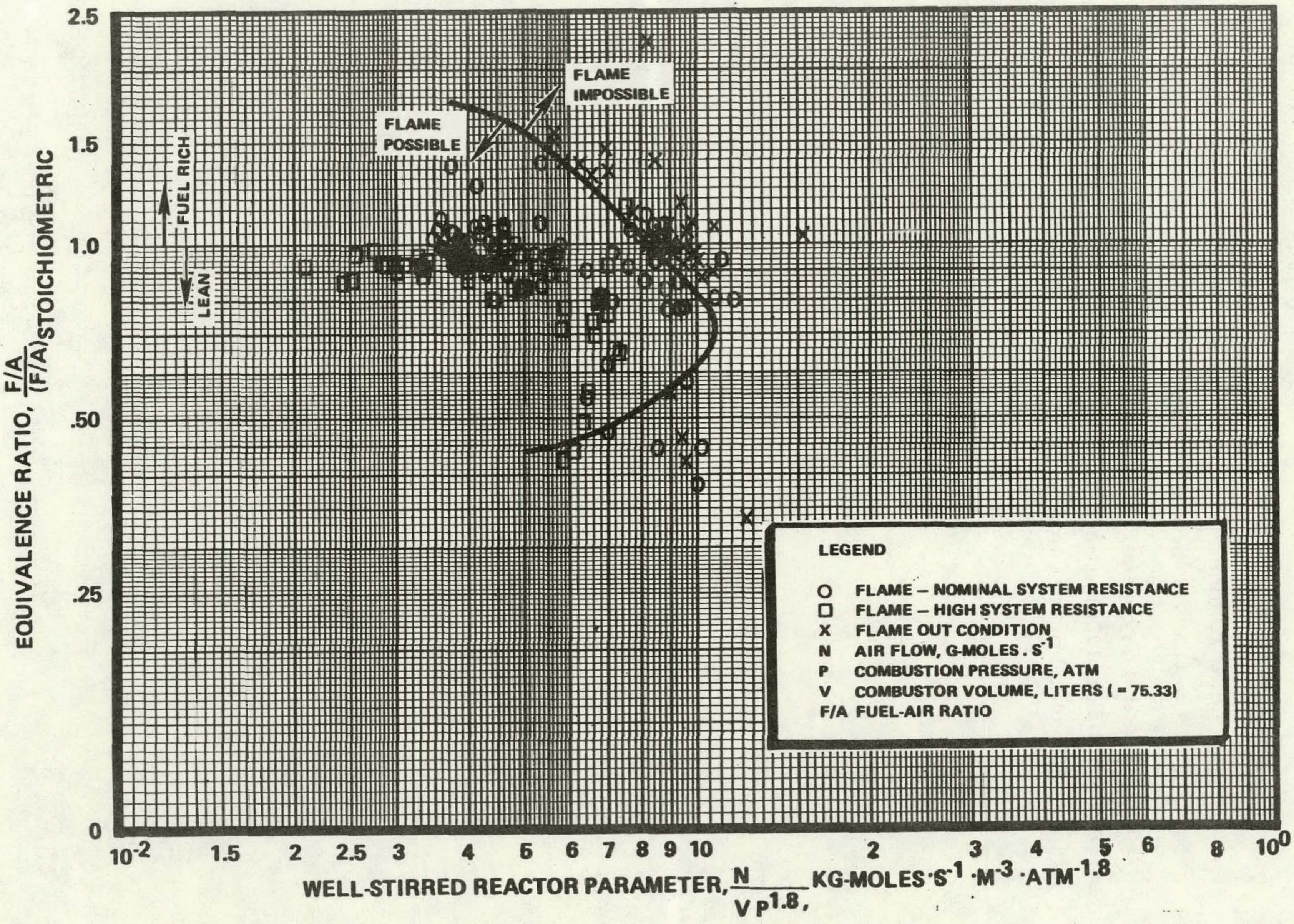


Figure 7. Combustion Characteristics

Discussion

- The carbon layer that is deposited soon after ignition creates resistance that reduces overall thermal efficiency measurably, especially in a small-scale system such as that described.
- A 1000 barrels/day generator could be scaled to nearly the same size of a 300 barrels/day generated by increasing the combustion chamber pressure.

IN-HOUSE STEAM GENERATOR ACTIVITIES

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Steam Generator Development

Fuels under consideration for use in the downhole steam generator vary from No. 2 fuel oil to No. 6 residual oil; No. 2 fuel oil is easier to burn but also more expensive. Long-range goals include studies for the efficient combustion of heavy fuels -- perhaps even upgraded lease crude. Techniques which are candidates for promotion of efficient combustion of heavy fuels are (1) preheating for good atomization, (2) blending with lighter hydrocarbons to promote handling and atomization, and (3) emulsification to encourage atomization (microexplosion) and as a combustion temperature moderator. If significant amounts of vanadium are found in fuels, special consideration must be given to avoid structural problems. Additionally, fuel-bound nitrogen and sulfur are expected to contribute to the acidity of the steam condensate water.

Oxidizers under consideration include both air and oxygen. These gases differ in cost, handling, burner design, and reservoir interaction, with O_2 combustion resulting in a significantly higher partial pressure of CO_2 in noncondensible injection fluids. Because of these differences, particularly in reservoir interaction -- an effect which cannot be modeled accurately by codes or bench-scale simulation -- a field demonstration utilizing these two oxidizers in side-by-side comparison is recommended and planned. For an oxygen system, liquid storage and pumping, but vapor injection to the steam generator, is being considered. The gaseous state, top-hole, will avoid the problems of maintaining a cryogenic delivery line to the downhole steam generator.

For downhole ignition, two systems are being tested: a glow plug and a pyrophoric fluid (triethyl borane (TEB)). A low-current (~5 amperes) glow plug is not anticipated to require a downhole transformer. However, either new types of glow plugs or an altered ignition sequence will be required to minimize the frequency of burnout. (In the Bakersfield test, approximately 12 glow plugs failed with the surface steam generator.) If a glow plug fails in a downhole generator, the fuel line can be used to inject a slug of pyrophoric to cause ignition. This slug will be immediately followed by fuel to sustain combustion. However, in 2000 to 5000 feet (610 to 1525 meters) of tubing, a significant amount of mixing and dilution of the pyrophoric with fuel will result. If the mixture falls below a critical value (10% in the case of TEB in diesel), ignition will not result. To study this problem, tests were conducted in which a slug of TEB was injected into a 2500-foot (762-meter) tube (1/4-inch dia.) of flowing diesel, shown in Figure 1. In the first test, 300 ml of 50/50 TEB/diesel was injected; ignition did not result, as can be seen in Figure 2(a). In the second test, 250 ml of straight TEB was injected; as shown in Figure 2(b), ignition resulted.

Testing activities to date have been limited to testing the Bakersfield steam generator, modified to burn with diesel fuel. Combustion chamber pressures have ranged up to 1100 psi (7.6 MPa). This test series will be used to evaluate such things as ignition methods and procedures, nozzle influence on combustion quality and stability, and the effect of pressure on combustion efficiency. Future tests will be conducted on units which could ultimately be candidates for downhole usage. Designs are also being considered which can utilize gaseous oxygen as an oxidizer.

Support and Facilities

The DEEP STEAM test area is nearing completion. Air can be supplied by either blowdown air (360 ft^3 at 3500 psi (10 m^3 at 24 MPa)) or by engine-driven compressors (750 ft^3/min at 1350 psi (0.354 m^3/min at 9.3 MPa)). Oxygen supply will consist of 4000-gal (15-kl) liquid storage, pump, vaporizer, and gaseous storage. Gas

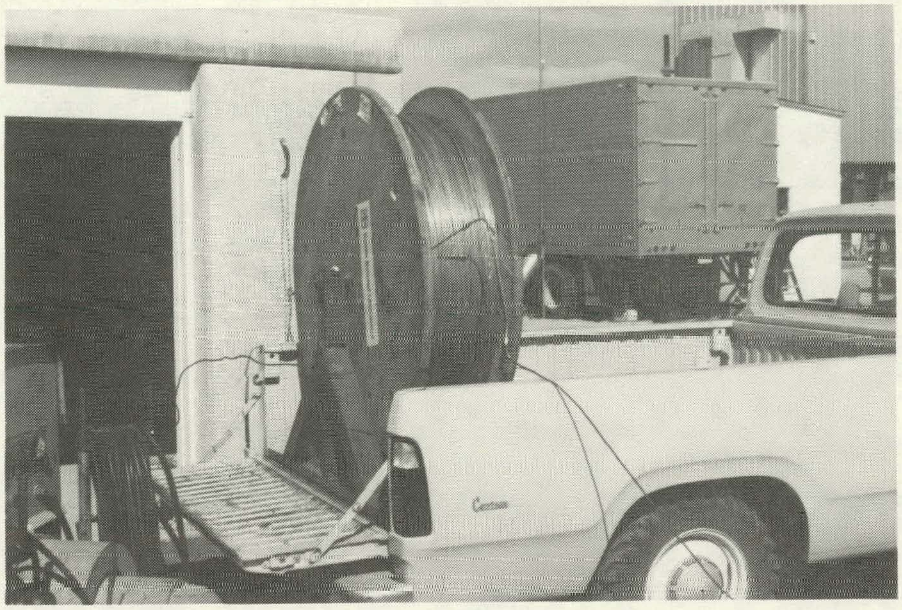

Figure 1. Tubing for Ignition Tests

(a)

(b)

Figure 2. Failure to Ignite with 50/50 TEB/Diesel Mixture (a), and Ignition with Straight TEB (b)

diagnostics will be obtained via the environmental sampling trailer, and operating information will be acquired and stored by the field test facility (B49). The generator testing will be sited either in a concrete bunker or in a test hole which is being drilled to approximate downhole deployment. Two separate support systems are being constructed: one will support combustion with diesel/air, the other will support combustion with diesel/oxygen.

SUPPORTING ACTIVITIES

RESERVOIR MODELING

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The waterflood option on code DSPM was extended to include the energy equation, simulating a two-phase hot waterflood. This option performed well, with no significant deterioration in iterative convergence. Because of the fully implicit technique, the limitation on the time step is only due to accuracy rather than stability; relative saturation changes of 50% over a single time step have been run, with monotone solutions being produced. The code was also restructured to reduce subprogram calls at some storage expense.

The data for the five-component, three-phase system was supplied to Ecodynamics by F. M. Orr and A. Yu of New Mexico Institute of Technology. The codes provide K-factors and thermodynamic data for mixtures of O_2, N_2, H_2O, or C14 and C45, in liquid and vapor phases. These subroutines were restructured to be compatible with the reservoir simulator and have been incorporated in code DSPM. The total code is now in the final stages of debugging. It is expected that the code will be exercised on the five-component, three-phase system within a month.

FRONTAL STABILITY

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The onset of hydrodynamic instability in a reservoir being flooded by a drive fluid can adversely affect the sweep efficiency. This instability, of "fingering," is illustrated simply in Figure 1; the phenomenon is of particular concern when a complex mixture of steam and flue gases is injected into the reservoir.

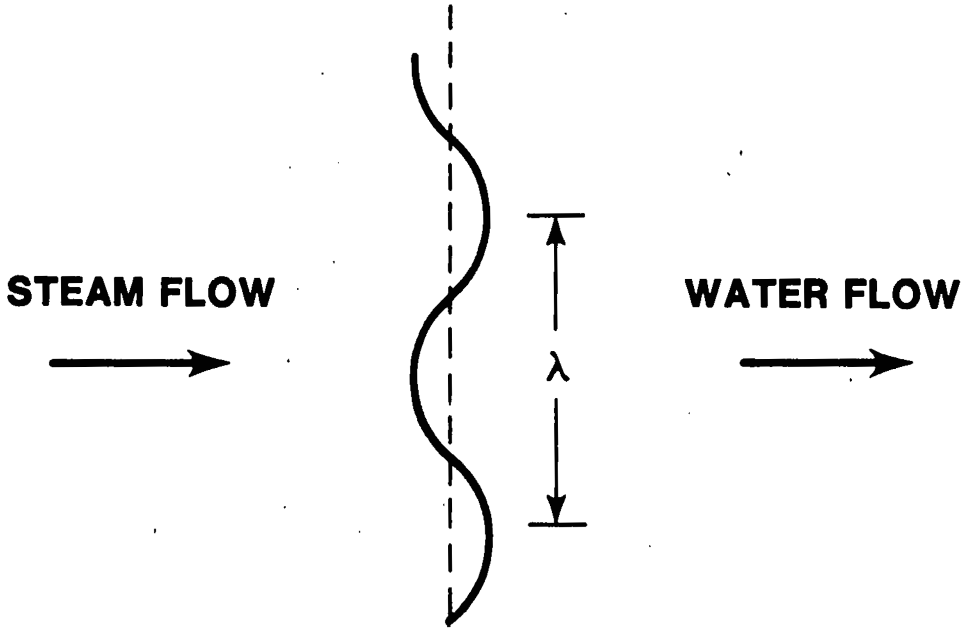

Figure 1. Frontal Instability Model

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[*] Reporting on research by D. A. Krueger, Colorado State University.

A linear stability analysis has been performed for a drive fluid consisting of nitrogen and saturated steam injected into a porous medium filled with water. Although this system is somewhat simpler than the prototypical system, it offers several insights into the stability of such a system.

The results of the analysis confirm the previously obtained results that steam condensation is stabilizing at low temperatures but is destabilizing at higher temperatures. The effect of nitrogen was found to be destabilizing at low temperature, but, surprisingly, stabilizing at high temperature. Further research will include the effects of steam quality and the presence of oil in the system. The relative importance of fingering as a mechanism for producing deviation from a piston displacement will also be addressed.

DIAGNOSTICS

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Three experimental programs are reviewed very briefly: steam quality measurements, particulate sampling techniques, and propane vaporization studies.

In house at Sandia, downhole and surface steam quality measurement techniques are under development. In the field, the downhole sampler failed during a trial at the Laramie Energy Technology Center tar sands steam project in Vernal, Utah, and a second-generation design, illustrated in Figure 1, is in progress. A surface technique was demonstrated and the results compared to the Total Dissolved Solid method. The agreement between methods was within ~5%.

The particulate sampling technique assesses the performance of the development models of the direct contact steam generator using a probe and gas dynamic expansion to obtain a filter sampler on polycarbonate filters. The filter samples are analyzed to whatever extent desirable. An optical technique utilizing extinction and absorption by particulate has been developed for use on direct high-pressure combustion studies. The technique, illustrated in Figure 2, uses two laser wavelengths and provides information on both number density and particle size. This method is applicable only to combustion product flow and is not useful for steam/combustion products combined.

In the Bakersfield field test on propane vaporization in the steam generator, laser scattering was used to discriminate between propane vapor and propane aerosols. The test apparatus is illustrated

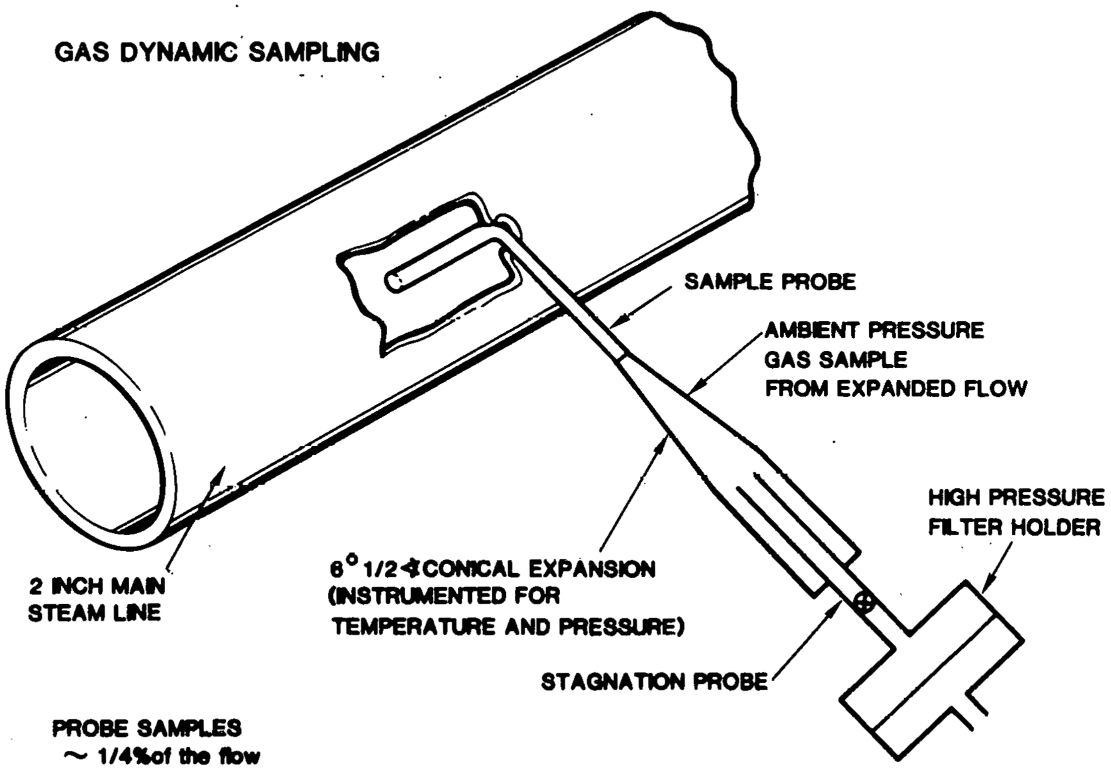

Figure 1. Gas Dynamic Sampling Probe

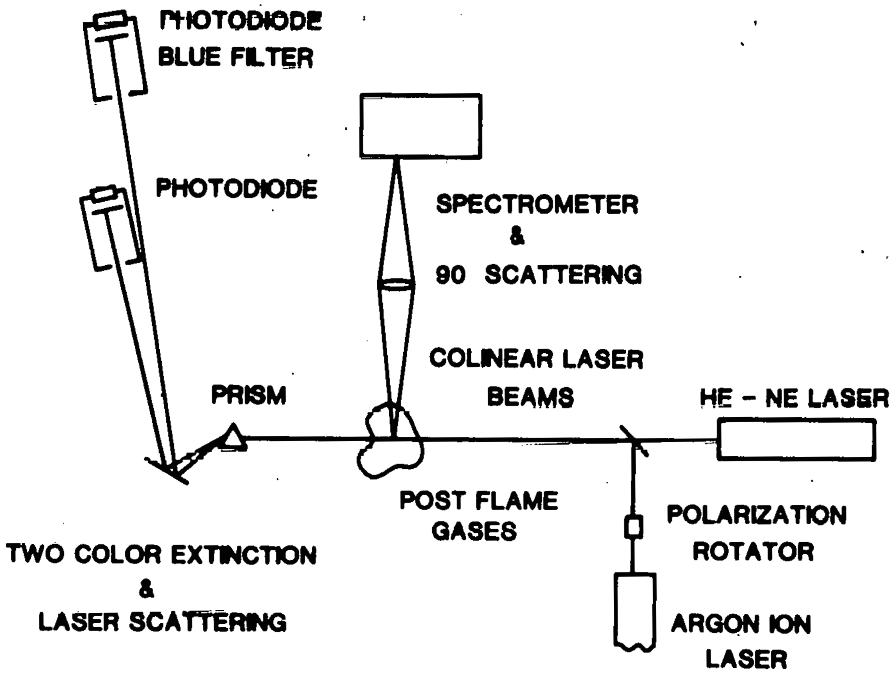

Figure 2. Two-Color Extinction and Laser Scattering Technique

in Figure 3. The results, charted in Figure 4, indicate that the Bakersfield design did not completely vaporize the propane before the combustion zone. Extrapolation of the data will provide guidance for future propane vaporizer designs.

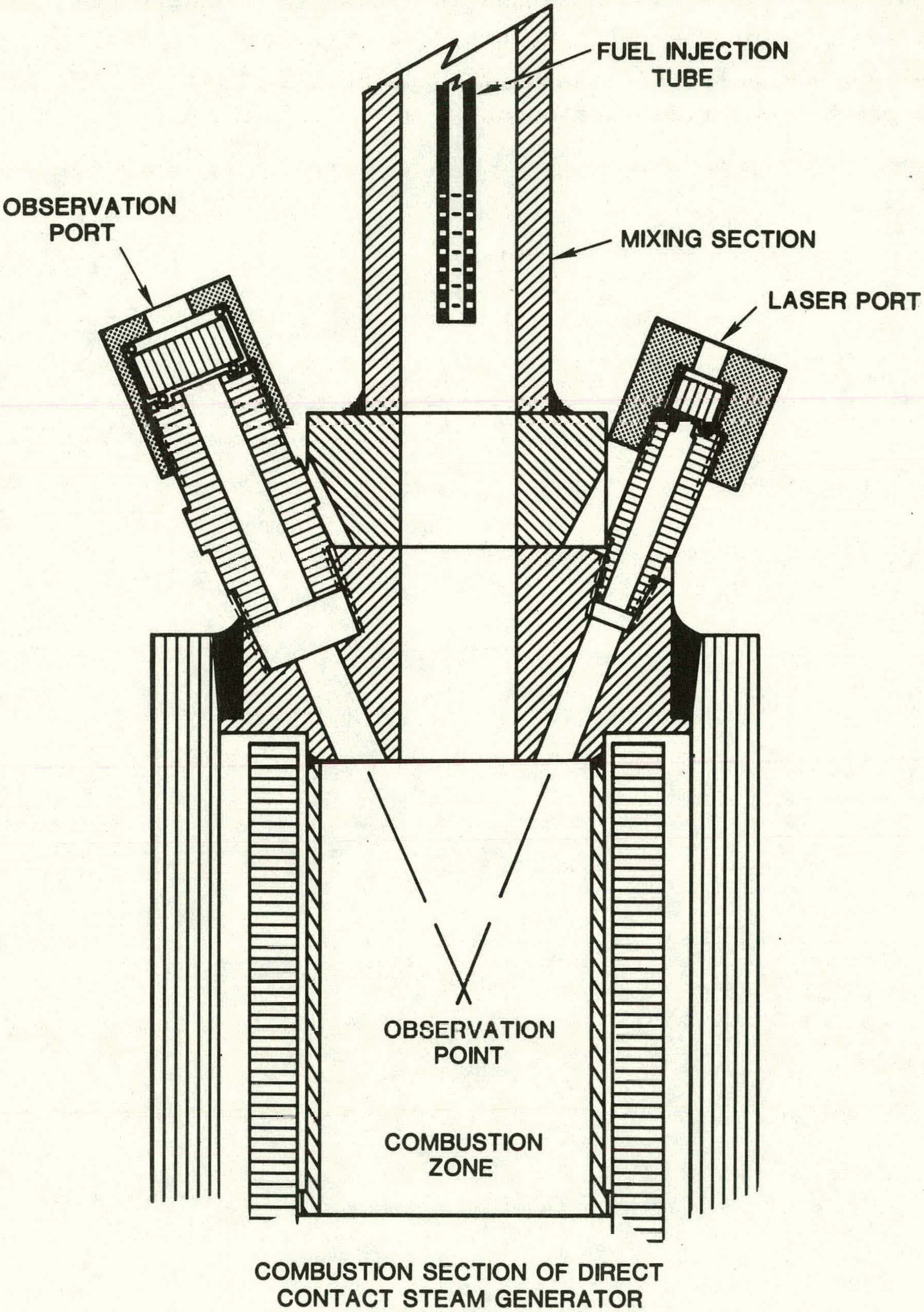

Figure 3. Propane Vaporization Test Setup

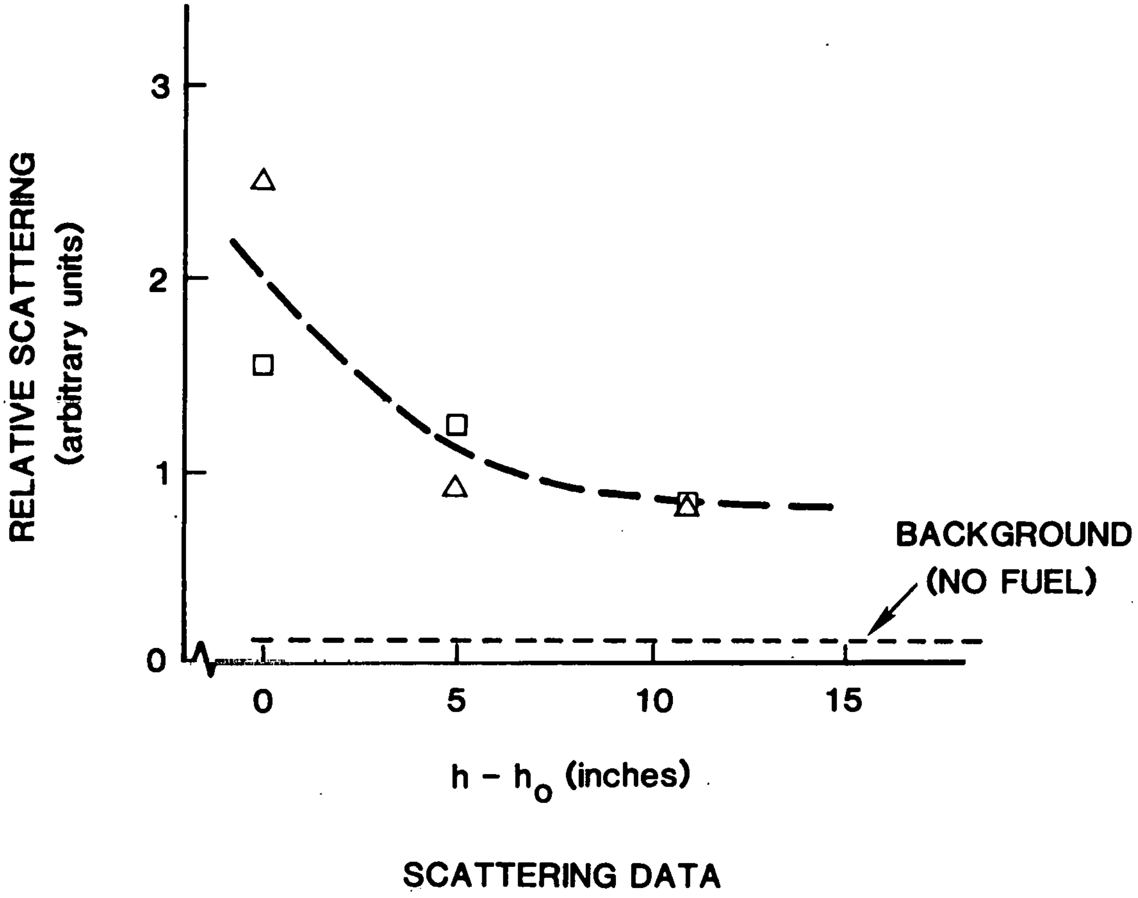

Figure 4. Relative Scattering versus Distance from Mixing Point for Propane Aerosols

AUDIO MAGNETOTELLURIC TEST

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The tracking of steam-drive thermal fronts by surface measurement techniques is an important aspect of improved well stimulation. There are numerous electrical and electromagnetic geophysical techniques that might be applicable. Almost all depend upon the higher electrical resistivity of the oil pay zone with respect to the surrounding strata because of the resistive nature of the oil. During a steam drive EOR process, the heated region will be of a lower resistivity because of the presence of hot steam, the heated groundwaters, and the absence of oil. The oil front will probably be a high resistivity region because of the presence of excess oil and absence of groundwater. The objectives of this study are to evaluate and improve the effectiveness of surface electromagnetic (EM) exploration geophysical techniques that can be used to (1) map and monitor the thermal recovery process for tar sands and (2) explore and map shallow tar sands deposits. More specifically, field tests of controlled source audio magnetotelluric (AMT) and pulsed or transient EM techniques will be conducted for evaluation of their applicability to this objection.

The benefit of the AMT to the tar sands program will be to adequately assess the efficiency of and the controls applied to the thermal recovery of heavy oils. The AMT method may allow mapping and monitoring of the progress of the recovery process. In addition, adequately planning the recovery of the tar sands oils in a particular field requires knowledge of the areal extent and depths of the reservoirs. Seismic reflection data alone cannot supply this information. There is speculation among various exploration geophysicists that the proposed EM techniques may be used to directly indicate the presence of hydrocarbons. The proposed project will address the evaluation of the use of EM techniques to map shallow deposits and monitor thermal recovery process.

The survey method used in the first phase of the program involves the measurement of fields around a grounded dipole. Without a detailed examination of the electric and magnetic fields associated with a grounded dipole, it is impossible to make accurate prediction from an analysis of field data. Many solutions exist for different geometries but all require reformulation into a form that will allow analysis of site-specific measurements. One example that indicates the approach is given by Foster* for the case of dipole grounded into a layer of given thickness and resistivity over a half-space of given resistivity. By examining the behavior of the field with distance from the source, it is possible to calculate the apparent resistivity, ρ, as follows:

$$\rho = \frac{1.26 \times 10^5 \ (E/H)^2}{f} \tag{1}$$

where E is the electric field in volts per meter and H is in ampere turns per meter for a source of frequency F. More detailed solutions will solve Maxwell's equations for the components of the Hertz vector Π, i.e., each component of the Hertz vector satisifies

$$\nabla^2 \Pi_{ik} - \delta_i{}^2 \Pi_{ik} = 0 \tag{2}$$

where

$i = 0, 1, 2$
$k = x, z$
δ = propagation constant.

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[*] R. M. Foster, "Mutual Impedance of Grounded Wire Lying on the Surface of the Earth," Bell Syst. Tech. J. 10, pp 408-419.

Then the electric field E is given by

$$_{i}-c\gamma_{i}^{2}\Pi_{i} \tag{3}$$

and the magnetic field H is given by

$$H_{i} = \frac{-jc}{w}\gamma_{i}^{2}\ \nabla \times \Pi_{i} \tag{4}$$

where C is the velocity of light, w is the angular frequency, and

$$\gamma_{i}^{2} = j\ 4\pi w\sigma_{i} - w^{2}E_{i} \tag{5}$$

where σ is the conductivity and E the permeability. The solution of these equations gives a near- and far-field solution that is frequency dependent. Thus the analysis of measurements must include this effect and a proper interpretation of measured E and H fields. At the present time, calculations are being set up for analysis purposes.

This approach was tested in Laramie Energy Technology Center's (LETC) steam injection experiment TS-1S in the tar sands outside of Vernal, Utah. The experiment site, 4 miles west of Vernal, is in the Northwest Asphalt Ridge deposit on Sohio National Resource Company property.

A series of AMT measurements was made where the electromagnetic field was produced by a grounded bipole source. The electric field was measured by a dipole receiver in contact with the ground, and the magnetic field was measured with a ferrite coil magnetometer. Soundings were made by varying the frequency from 4 to 2048 Hz and lateral variations, by moving the receiving antenna. The first set of measurements in late May 1980 concentrated upon the terrain between 3I1 and outpost 3P6, as shown in Figure 1. A resistivity low found near 3I1 increased to a maximum away from the injection well and then decreased to a background value further away from 3I1. Later tests indicated that the presence of plumbing does not have detrimental effects on AMT measurements.

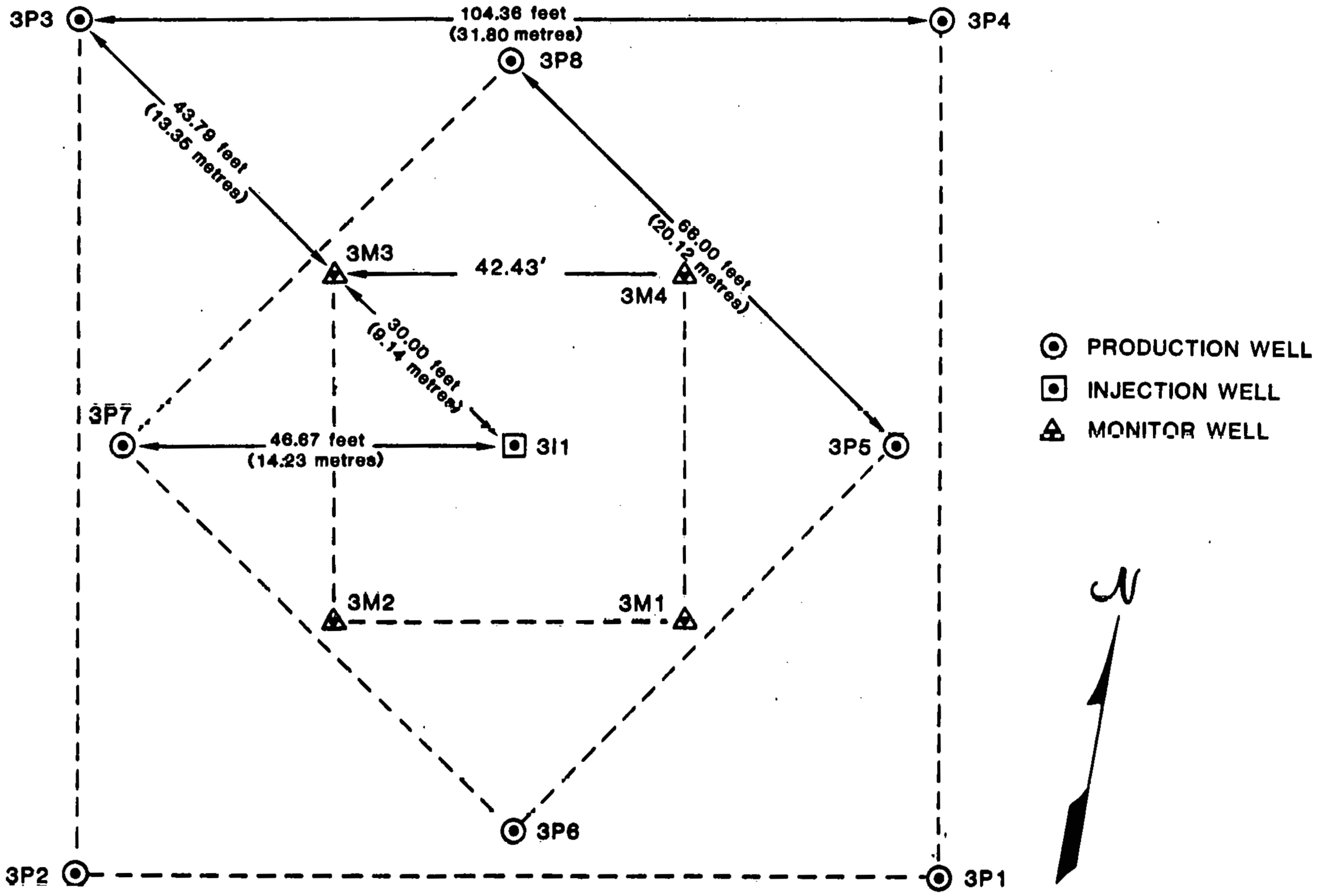

Figure 1. LETC TS-1S Well Pattern

This set of preliminary results encouraged a complete survey of the injection site on 20-22 June 1980. The results of this survey are shown in Figures 2 through 6. Each data collection point is shown by a dot overlain upon the well pattern of Figure 1. The numbers beside each dot are the apparent resistivity in ohmmeters at the indicated frequency. The contours are best estimates of the constant resistivities (indicated by the circled numbers). The analysis of the data is not complete, so interpretation cannot be made at this time. However, a number of observations can be made to indicate possible interpretations. Temperature measurements in 3M1-3M4 indicate that the steam has developed most strongly along the lower layer of the pay zone, with some heat toward the top of zone at 500 feet (152 meters). The

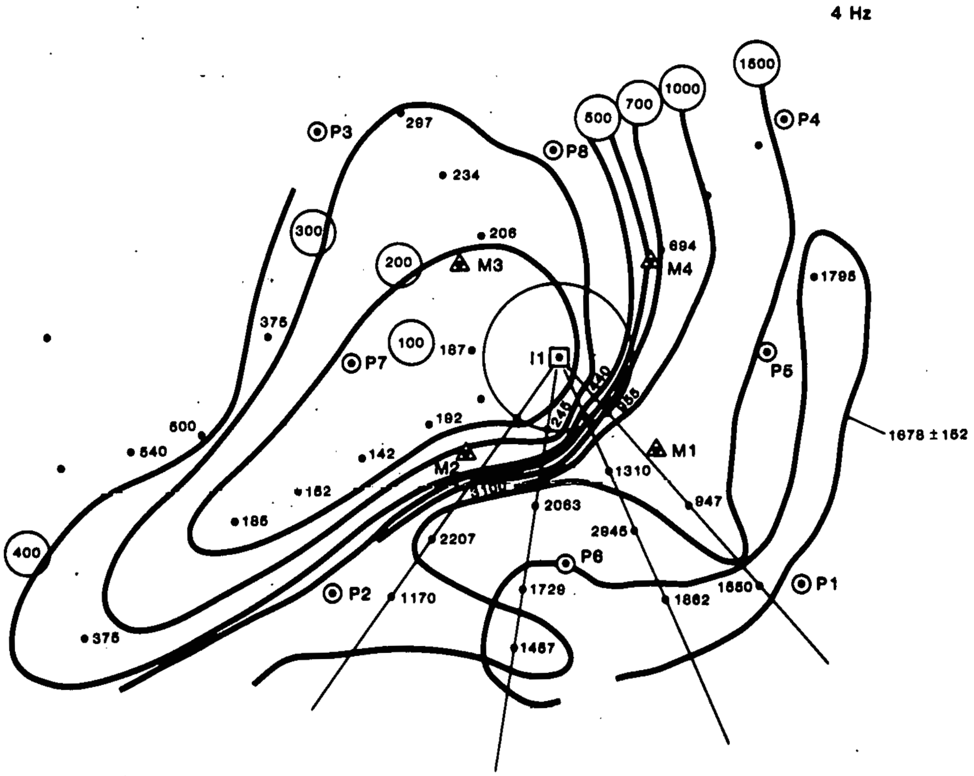

Figure 2. AMT Resistivity at 4 Hz for the TS-1S Experiment on 22 June 1980. The contours of constant resistivity are in ohmmeters.

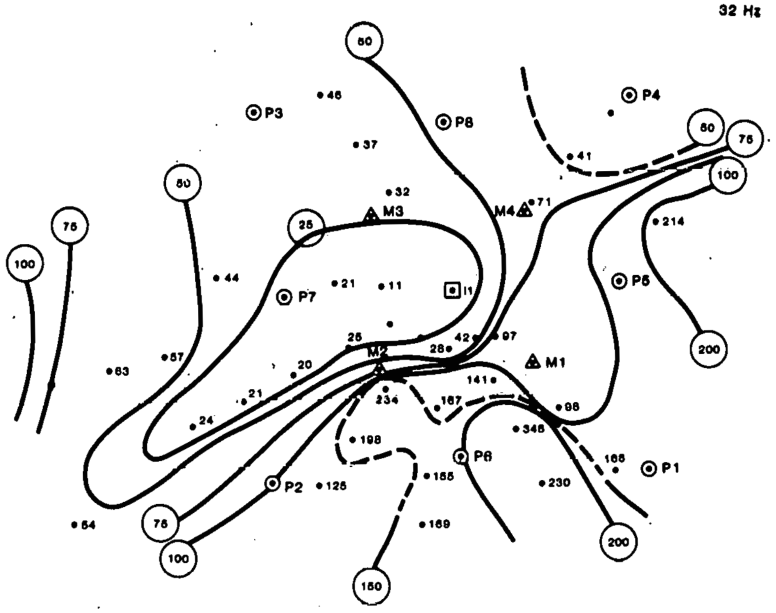

Figure 3. AMT Resistivity at 32 Hz

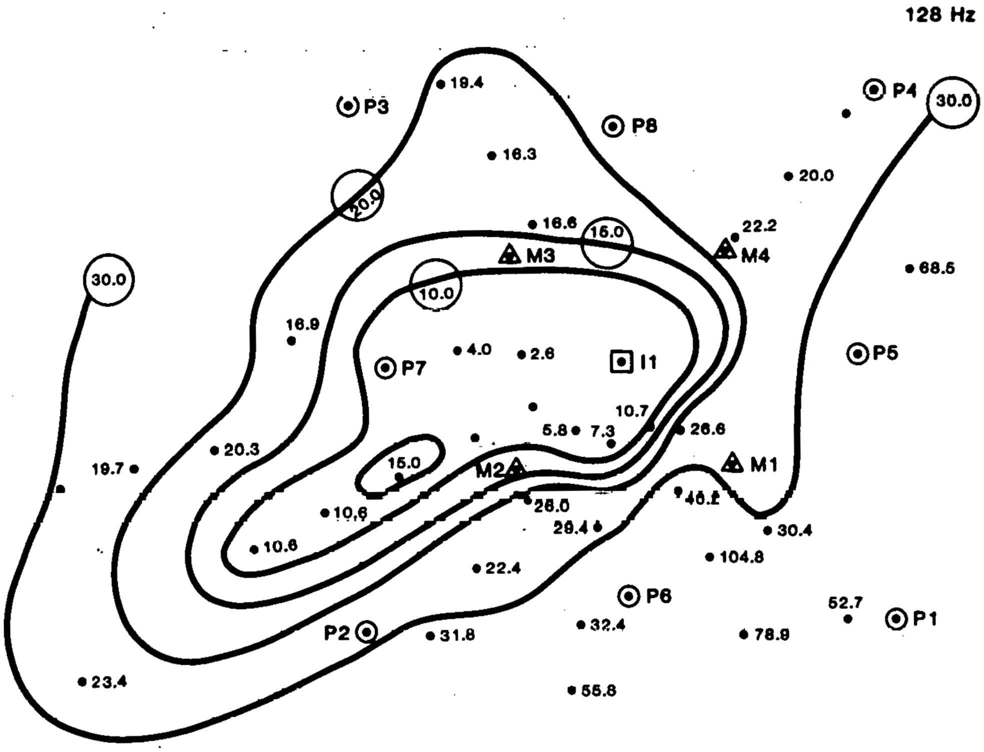

Figure 4. AMT Resistivity at 128 Hz

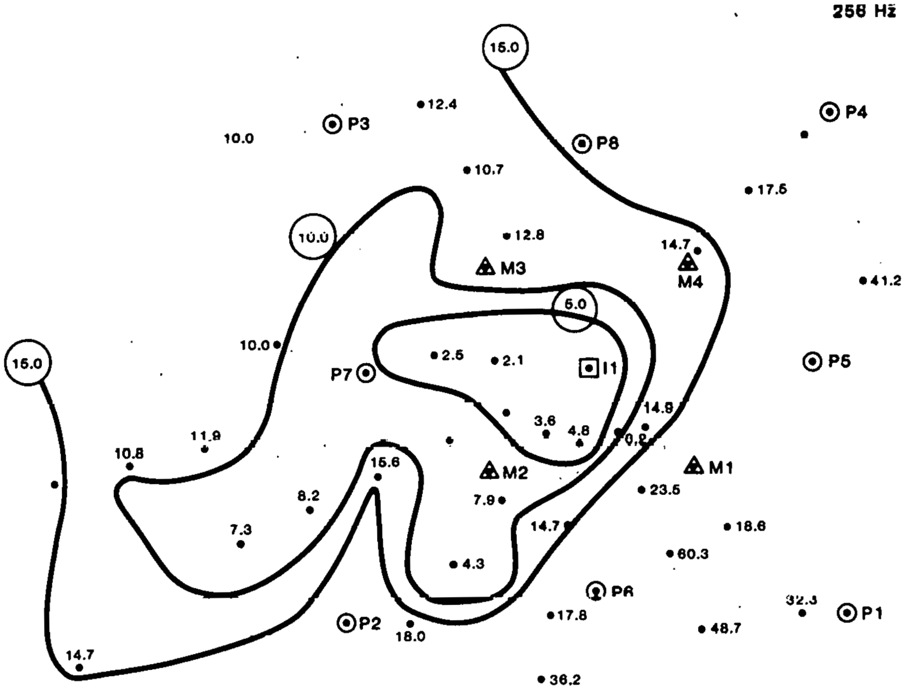

Figure 5. AMT Resistivity at 256 Hz

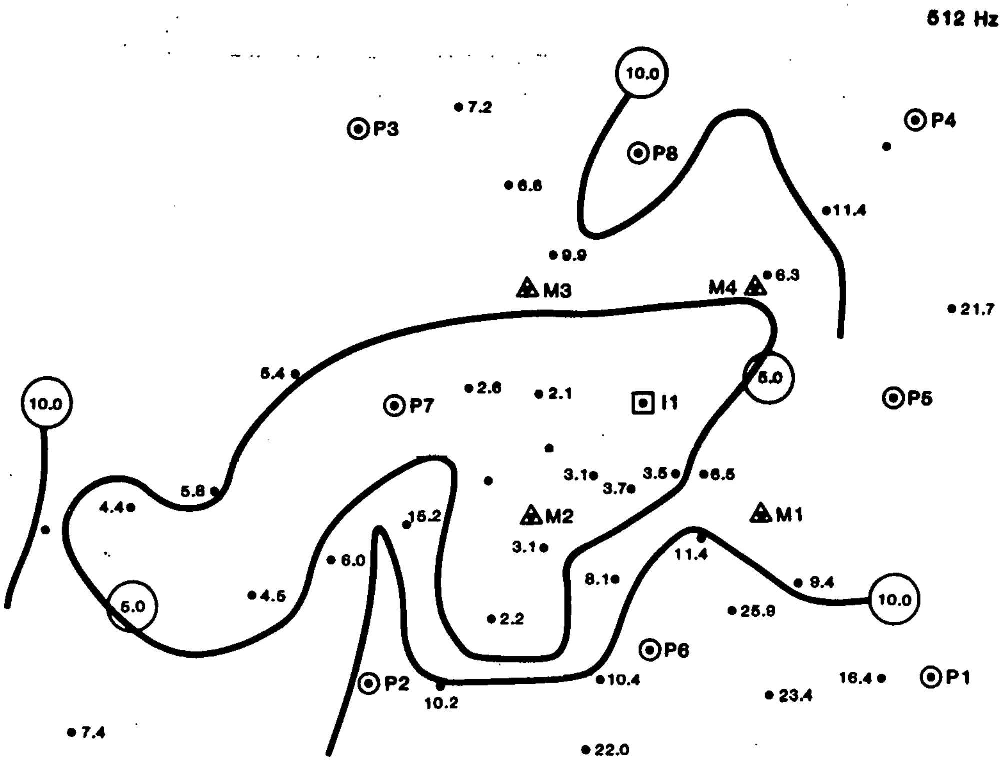

Figure 6. AMT Resistivity at 512 Hz

higher temperatures on 20-22 June 1980 were in 3M2 and 3M3. Thus, the 4-Hz results shown in Figure 1 follow a pattern that is consistent with the observations from the production and monitor wells. (3P2 and 3P3 were not operational at the time of these measurements.) The same general phenomenon is seen up to about 128 Hz (see Figures 2, 3, and 4). However, at 256 and 512 Hz, the pattern really began to break up. In fact, the higher frequencies (1024 and 2048 Hz) are not shown for this reason. Recall that the higher the frequency, the shallower the zone sampled by the AMT. As a hypothesis, if the pattern shown for 4 Hz is assumed to be the steam front, then 3P7 and 3P8 should be the best producers. But then the next two wells to start up should be 3P2 and 3P3. By the end of July, the steam front was at 3P8 to the extent that there was sufficient pressure to produce without pumping. Also 3P3 had produced for a while, but sand control problems had shut it down.

Discussion

- Reservoir water content is a major factor affecting resistivity and can be thought of as analogous to the dielectric constant.
- The lower the frequency used, the deeper the measurments that can be made. With frequencies on the order of 0.001 Hz, it may be possible to make measurements 2500 to 3000 feet (760 to 915 meters) below the surface.
- Work is underway on three-dimensional interpretation and presentation of data.

COMPARATIVE ECONOMICS

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This discussion addresses general economic considerations for the following surface and downhole technologies:

Surface Technologies

- Conventional steam drive with bare tubing
- Conventional steam drive with thermally efficient well completions.

Downhole Technologies

- Low-pressure combustion generator
- High-pressure combustion generator using atmospheric air
- High-pressure combustion generator using pure oxygen.

Two measures have been chosen to determine the relative economic performance of the technologies: cost of sand-face steam delivery and cost of oil recovery. Use of the former performance measure is based on the premise that all technologies which deliver pure steam to the sand face at the same rate, same quality, and same pressure are equivalent insofar as the reservoir is concerned. However, the solubility effects of CO_2 (which are important for downhole high-pressure combustion designs that mix steam with combustion products) do not exist for pure steam injection. To evaluate technologies that include exhaust gas injection, the economic analysis should not be based on the cost of steam delivery but rather on the later performance measure, the cost of the oil recovered. This means that a reservoir production model must be included in the analysis. It is generally recognized that of all the elements that constitute the cost analysis, the reservoir production estimates are the least certain. In other words, significant noise is introduced into the comparative cost analysis when oil production is included because of lack of confidence in model output and/or the nonexistence of empirical field data. Because there are disadvantages associated with each of the aforementioned performance measures, both were employed to investigate the relative merits of the deep steam technologies. Cases for both performance measures follow.

The pertinent parameters used in the steam delivery cost analysis are given in Table 1. The annualized costs were calculated using a uniform end-of-series payments cost formula which has a component that reflects the investment in capital equipment and a component that represents the direct yearly operating costs, adjusted for inflation. The capital and operating costs required are displayed in Table 2.

Table 1

Steam Delivery Assumptions

Reservoir	
Depth	500 to 5000 feet (150 to 1500 meters)
Original formation pressure	Hydrostatic (0.43 depth) psi
Steam Generation	
Injection pressure	Reservoir pressure + 300 psi
Injection rate	500 to 1500 BCWE/day
Sand-face quality	0.20 to 0.80
Fuel	Diesel
Economic (Uniform series, end-of-period payments)	
Inflation rate	10%/year
Discount rate	12%/year
Life of system	10 years
Life of project	5 years

Table 2

Capital and Operating Costs

Capital Costs
Drilling and completing injection well
Crude treatment system
Water treatment system
Combustion gas treatment system
Piping, valves, structural
Packer
Compressor
Gas separator
Steam generator
Installation (incl. electrical contracting)
Miscellaneous

Operating Costs
Fuel
Maintenance
Water
Labor
Other

Sample outputs of the analysis are shown in Figures 1 and 2. The band representing surface steam generation with an insulated wellbore includes both a variance in cost and a range of values for conductivities of 1 inch of insulation. Figure 1 represents a case of 500 barrels of cold water equivalent (BCWE) steam being injected daily at hydrostatic + 300 psi pressure. The steam quality at the sandface for all systems is 45%. Similarly, Figure 2 depicts cost of delivering 1500 BCWE/day of 80% quality steam.

For the examples shown, two observations may be made:

1. As conventional steam generation (without thermal completions) becomes infeasible at low injection rates, one cannot readily distinguish between alternatives. That is, the

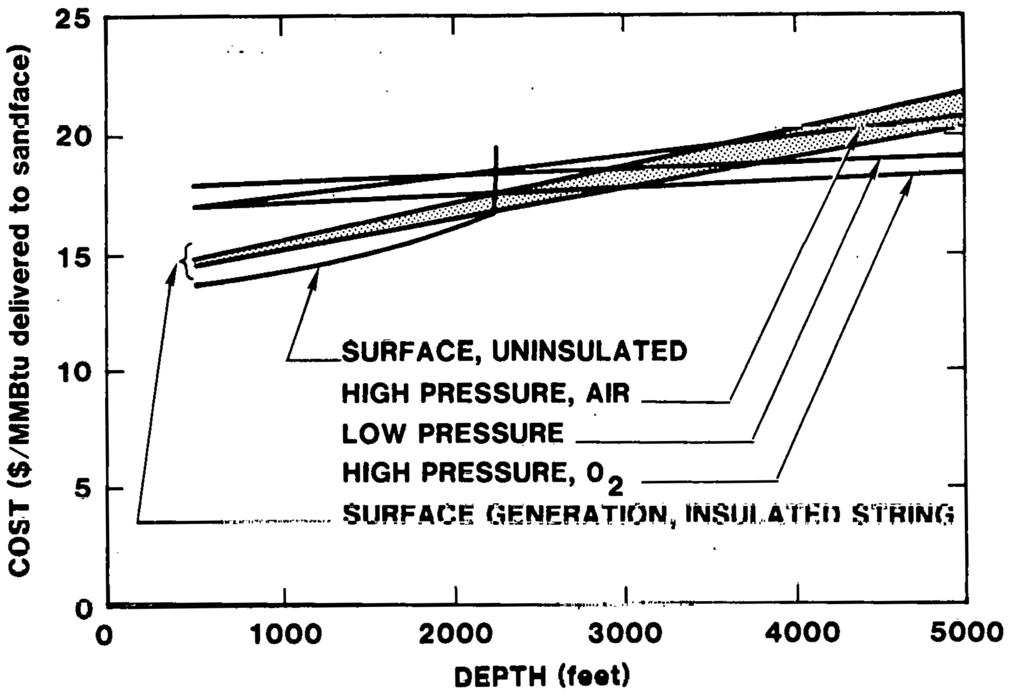

Figure 1. Steam Delivery Cost versus Depth, 500 BWCE/day of 45% Quality Steam

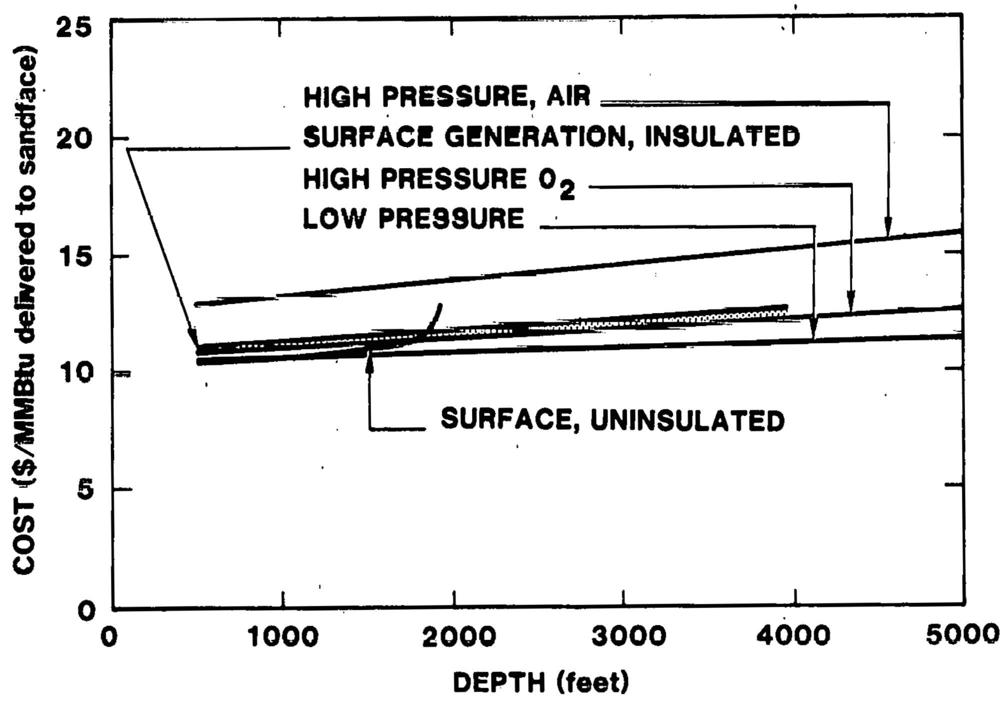

Figure 2. Steam Delivery Cost versus Depth, 1500 BWCE/day of 80% Quality Steam

differences shown in Figure 1 are insignificant because of errors in the cost data.

2. High injection rates result in a marked cost difference between the high-pressure combustion/air technology and all other technologies compared to the differential seen for lower injection rates.

Next, consider a cost analysis based on oil recovery. The characteristics of the reservoir and injected steam are given in Table 3.

Table 3

Oil Recovery Assumptions (INTERCOMP)

Reservoir Characteristics		
2.5-acre 5-spot		
Depth to top of formation	4200 feet (1280 meters)	
Thickness of pay zone	73 feet (22 meters)	
Oil saturation	60%	
Formation temperature	140°F (60°C)	
Oil gravity	10° API	
Oil viscosity	3300 cP at 140°F (60°C)	
Steam Factors		
Steam Quality	85%	
Maximum injection pressure	2300 psi (16 MPa)	
Injection rate	Average	Scheduled
Low-pressure combustion	315 BCWE/d	500 BCWE/d
High-pressure/air	231 BCWE/d	330 BCWE/d
High-pressure/oxygen	300 BCWE/d	330 BCWE/d

The cost of production was determined from a discounted cash flow rate of return (DCFROR) analysis. Cash flow is determined annually as indicated in Table 4. The DCFROR is the solution of a present worth equation

$$\text{Initial Investment} = \sum_{j=1}^{N} \begin{pmatrix}\text{cash flow in}\\ \text{period } j\end{pmatrix} \begin{pmatrix}\text{present worth factor}\\ \text{for period } j\end{pmatrix} + \begin{pmatrix}\text{salvage}\\ \text{value}\end{pmatrix} \begin{pmatrix}\text{present worth factor}\\ \text{for period } N\end{pmatrix}$$

where N is the life of the project.

Table 4

Cash Flow Determination

Gross Income
- Royalties (1/8 Gross)
- Operating Costs
- Intangibles
- Depreciables
- Windfall Profits Tax
= Taxable Income
- Tax (46%)
= Net Profit
+ Intangibles
+ Depreciables
= CASH FLOW

The oil production for the particular reservoir and set of injection parameters described in Table 3 was determined from the three-dimensional in-situ combustion code, INTERCOMP, developed by K. H. Coats of Resources Development and Engineering Co. of Houston. For the case being considered, output of that code is given in Figure 3. Although ultimate recovery is virtually the same in all cases, time of recovery differs dramatically. Results of the DCFROR calculations are provided in Table 5. Note that a third performance measure, that of technology efficiency, is included in this table.

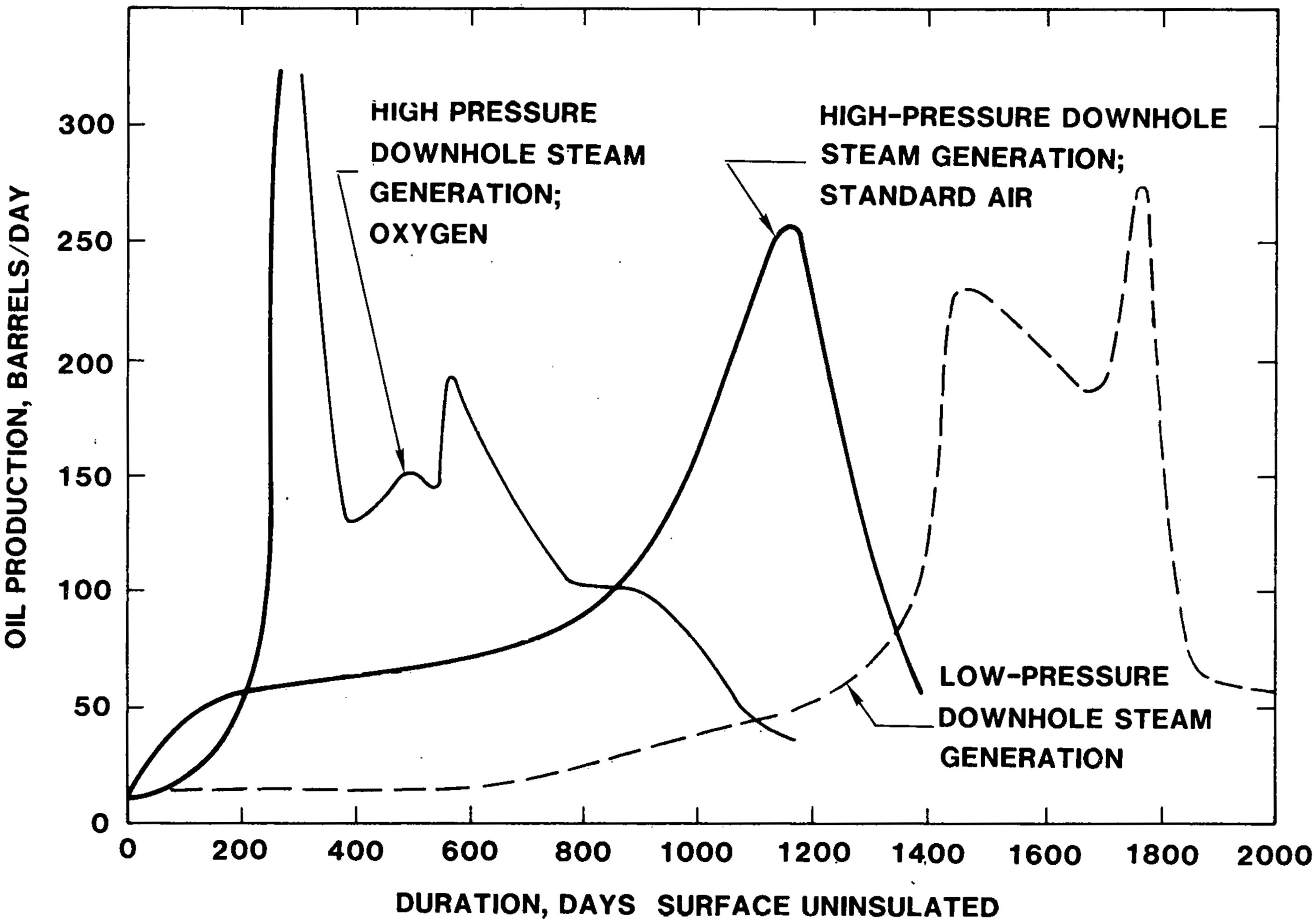

Figure 3. Oil Production Rate versus Time

Table 5

DCFROR Results

Technology	DCFROR	Efficiency (BBL produced/consumed)
Low-Pressure Combustion Generator	4%	2.0
High-Pressure Combustion Generator/Air	14%	3.0
High-Pressure Combustion Generator/O_2	23%	3.5

The resultant rates of return indicate that reservoir response is critical. As mentioned previously, an accurate assessment of reservoir production trends for all of the technologies considered is not currently available. In this regard, confidence in the results shown in Table 5 is low. Nonetheless, based on the production model output, early recovery due to combustion gas interaction with the oil in the reservoir substantially increases the DCFROR and dictates the technology that should be pursued.

FIELD TESTING

BAKERSFIELD TEST RESULTS

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The cooperative test by Sandia National Laboratories and Chevron USA in the Kern River Field near Bakersfield, California, was conducted for three main objectives. The first objective was to evaluate the performance of a downhole steam generator for a significant period of operation. The second was to evaluate the environmental implications of injecting steam and combustion products into the reservoir. The third was to evaluate the effects of noncondensible gases on the reservoir.

The experiment was conducted with a modified, commercial, propane-fired direct-contact steam generator. This generator was operated on the surface, with the steam and combustion products injected in an active 2.5-acre, five-spot steam drive, as shown in Figure 1. The generator was designed for 5 million Btu/h operation. It was run at ~3.5 million Btu/h with ~50% steam quality which matched the prior steam drive injection. The injection was 350 barrels/day cold water equivalent.

The first phase of the experiment lasted for 3 months, during which the generator and support systems performed without major problems. Ignition of the system proved to be the most troublesome aspect of the operation. During this phase, the production well effluents were compared to the injection well input and pollutants CO and NO_x were reduced substantially. These reductions, as well as the percentages of other gases present before and after the test, are given in Table 1. Transient effects on production were noted, but no long-term change in production occurred.

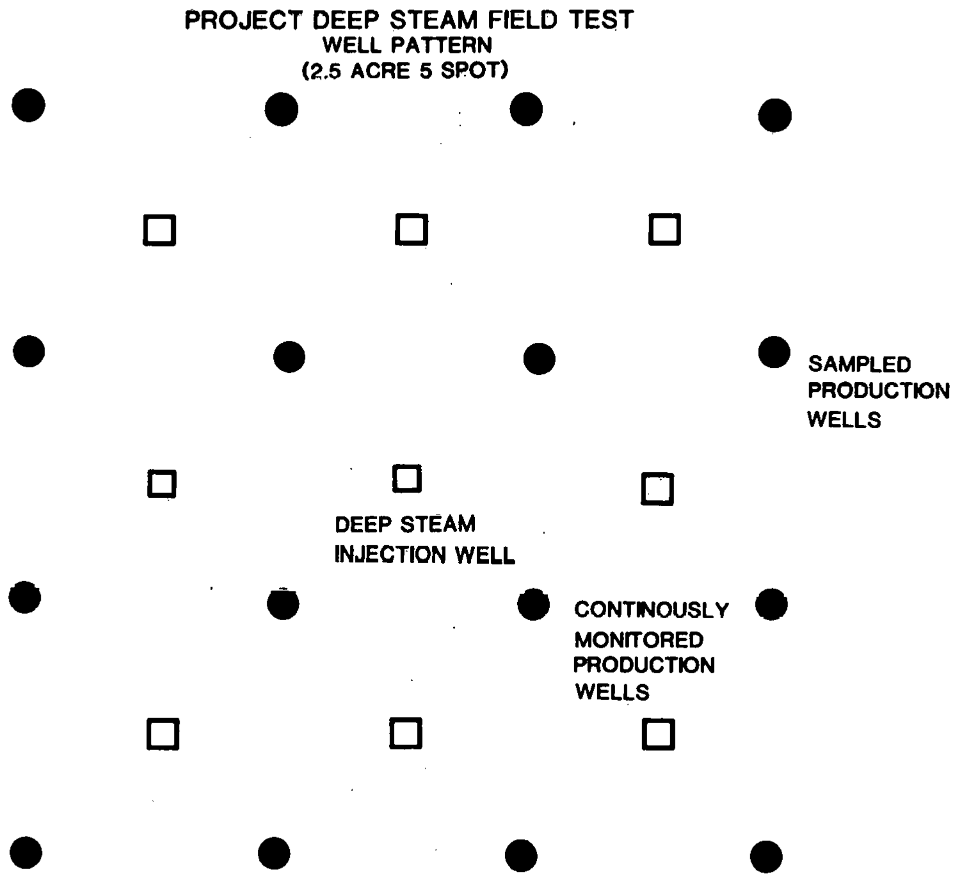

Figure 1. Bakersfield Field Test Well Pattern

Table 1

Project DEEP STEAM Field Test Gas Analysis

	Noncondensible Production Gas Before Test	From Generator	Noncondensible Production Gas During Test
N_2	55%	80%	80%
CO_2	40%	13%	13%
CH_4	Trace	None	Trace to 2%
H_2S	Trace	None	Trace
CO	None	3%	0.5 - 1.5%
NO_x	None	800 ppm	50 ppm
$_x^*$	None	5000 ppm	1 ppm

SO

*Sulfur test

The second phase of the field test was a foam blocking experiment conducted with Chevron. This experiment, illustrated in Figure 2, was designed to explore the usefulness of the noncondensible combustion gases as a foam stabilizer. A total of 50,000 gallons (190 kl) of 1% to 2% foam solution was injected. The foam was placed in the reservoir with air or steam/combustion products or blocks ranging from 1,000 to 5,000 gallons (3.8 to 19 kl). A continuous treatment over three days of 21,000 gallons (79 kl) was also injected. The result was the same in all cases: although reservoir back pressure increased during the foam injection, the back pressure decayed within several hours. Foam was produced at some of the production wells before the estimated volume of the high permeability channels was filled. A short test was run in which foam solution was added to the steam generator feed water. The effluent was foamy, indicating that the surfactant at least partially survived the direct contact with combustion products. No effects on production were noted throughout the foam experiment, but it was concluded foam injection is compatible with the downhole steam generator.

The final phase of the field test was to observe the recovery of the reservoir after DEEP STEAM injection ceased. The reservoir was back to its original condition 1 week following the experiment.

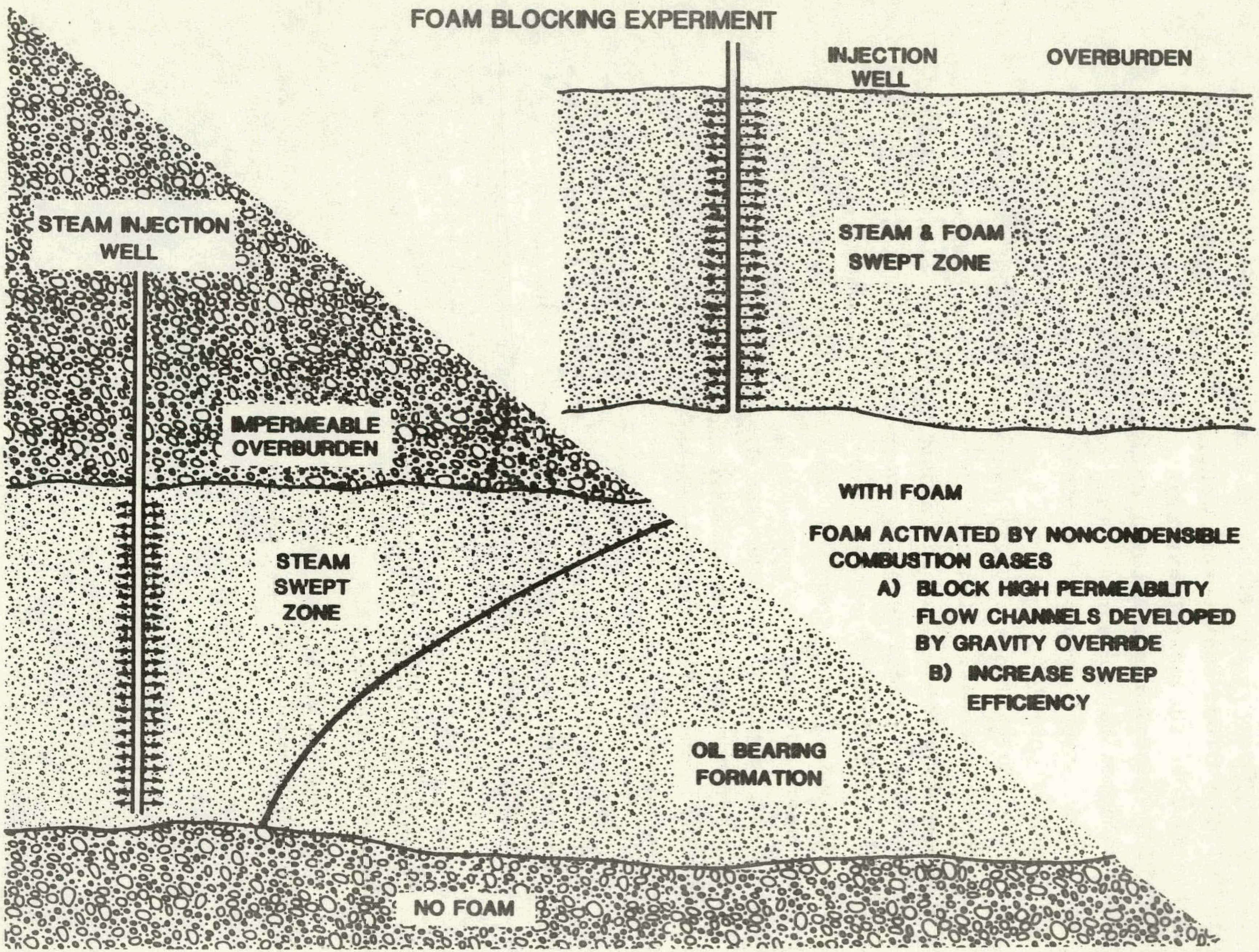

Figure 2. Foam Blocking Experiment

KERN RIVER RESERVOIR FLOW

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The flow of the multiphase fluids produced by the high-pressure combustion generator through the test reservoir is depicted in Figure 1. The flow processes in geophysical media are visually complicated by inhomogeneities. In addition to these complications, the test pattern included a mild dip and the influence of surrounding injection wells which were subjected to surface-generated steam throughout the field test operation. The flow processes were too complicated for a dynamic computational analysis; however, an analysis capable of quantitatively determining the global reservoir flow characteristics was necessary in order to monitor effects of the injection of combustion gases with steam on the reservoir.

A general statistical description of the reservoir flow can be obtained by considering the individual flow streams in the reservoir to be designated by a parameter "S". The probability distribution function for a particular fluid element to follow a flow stream "S" will be (15). The observable profile for arrival at a production well is related to the profile input at the injection well by an ensemble average over the flow stream distribution. The ensemble average can be written in the form of a convolution integral by a change of variable from the ensemble parameter to the temporal variable "t". The response function in the convolution integral was determined from the impulse response of the reservoir to a short term (few hours) injection from the generator. The response function contained parameters related to three global properties of the reservoir: permeability, tortuosity, and chemistry.

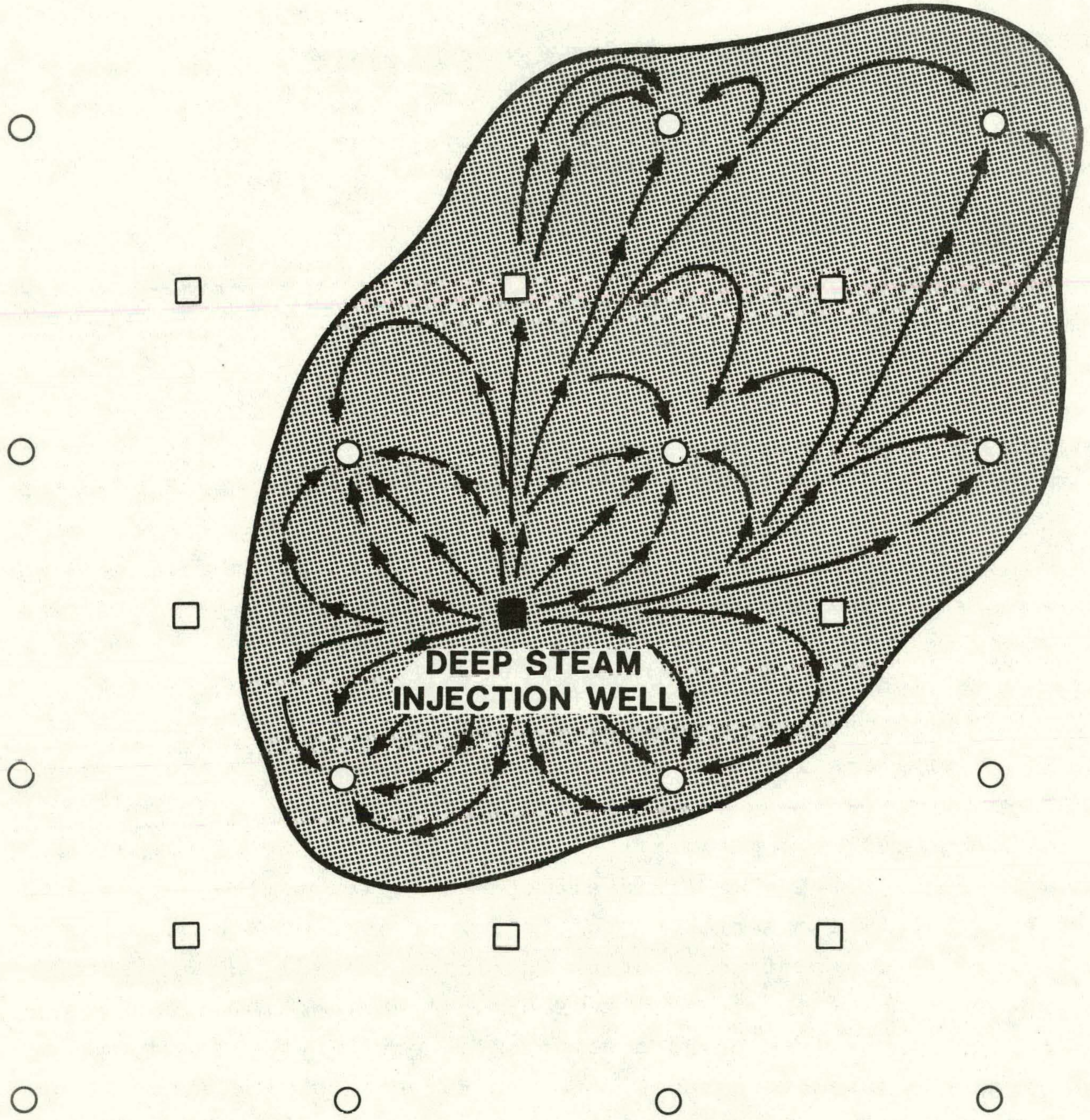

Figure 1. Project DEEP STEAM Field Test, Flow Field of Combustion Gases

The generator performance was quantified as a series of rectangle functions. The amount of non-condensible gas arriving at each production well was predicted by carrying out the convolution of the generator performance with the response function for the section of the reservoir influencing each production well. An example of the measured CO production with that predicted by this method is shown in Figure 2. The comparison shown is typical of that obtained for each well. The application of this method for analysis of the flow was successful in quantitatively providing the effect of the recovery operation on the reservoir.

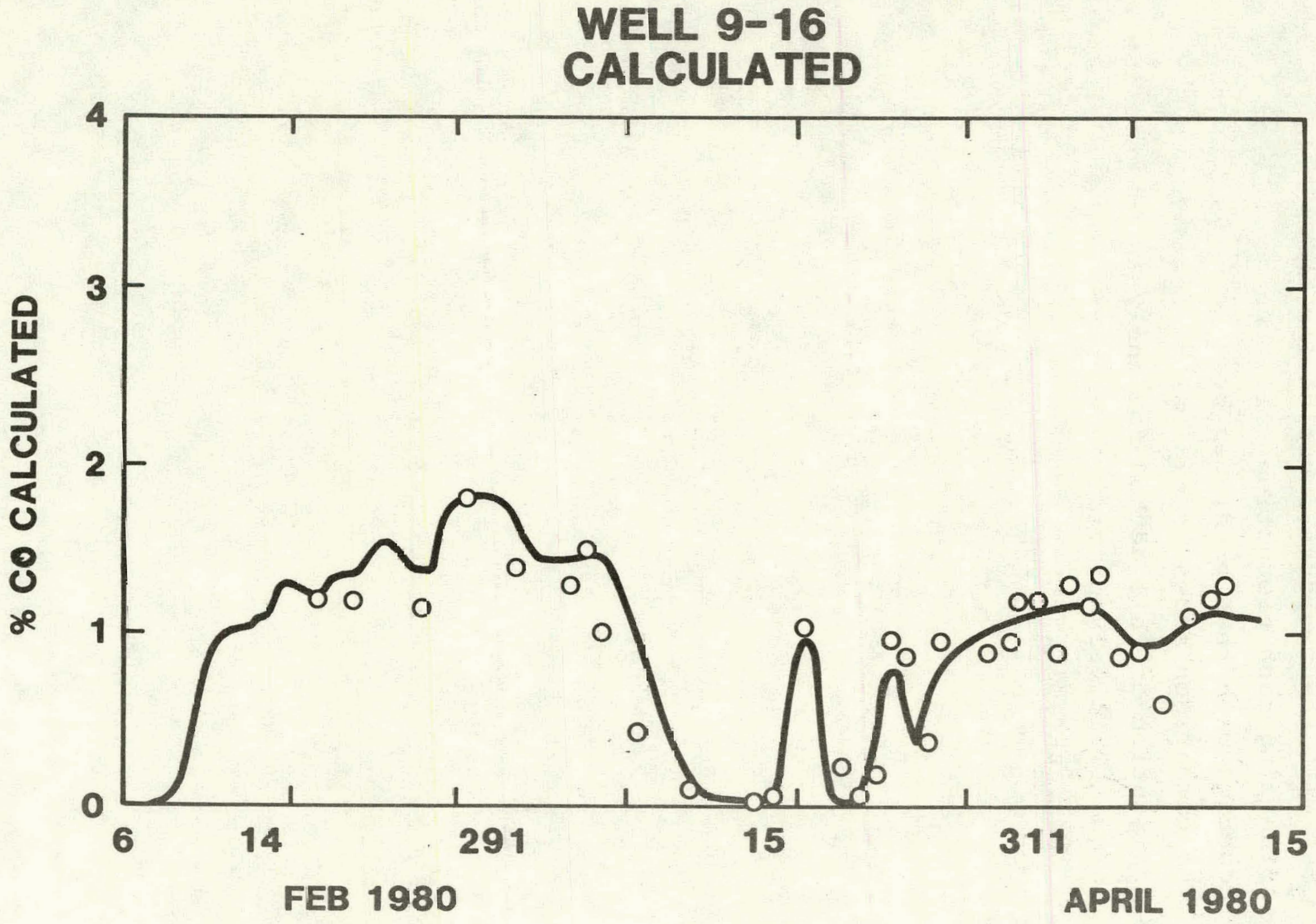

Figure 2. Measured CO Production (Solid Line) versus Predicted Values (Circles)

MATERIALS RESULTS—BAKERSFIELD FIELD TEST

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Materials coupons of 1018 carbon steel, 1095 carbon steel drill rod, and 303 Se stainless steel were exposed to steam plus combustion gases produced by prototype steam generators at test sites in Sandia Area III and in the Kern River Field, Bakersfield, California. The test environment for the 1/8-inch rod specimens was nominally steam, nitrogen, and carbon dioxide at 188°C and 340 psia.

Evaluation of the specimens following exposure revealed that in mildly basic steam, all three materials performed adequately for substantial generator operation times (approximately 25 days). As shown in Figure 1, the corrosion was little more than cosmetic. The most visible change took the form of a silicon deposit on the 303 Se stainless steel specimen, as shown in Figure 2(a).

An experiment which introduced SO_2 gas into the generator feedwater caused the steam discharge to become mildly acidic. During this exposure period, the corrosion rates for the carbon steel materials became unacceptably high. This was particularly true at the junction with the stainless steel specimen holder, where galvanic effects, possibly related to condensing steam, added to the corrosion rate. This corrosion is shown in Figures 3 and 4. The stainless steel specimen exhibited adequate corrosion resistance in this atmosphere, as shown in Figure 5.

An additional experiment, directed at determining reservoir interactions, added very high concentrations of SO_2 to the generator feedwater. This resulted in acidic steam (a measured pH of approximately 2), and the corrosive attack on all three materials was severe in this environment; extensive pitting of the 303 Se steel is clearly seen in Figure 6(a). Stainless-steel sheathed thermocouples were also attacked in the high SO_2 environment, as shown in Figures 7, 8, and 9.

Corrosion monitoring will continue during the next generator field test, which is to be conducted downhole and at higher temperatures and pressures. Preparation for the upcoming field test includes exposure of materials to various environments produced by prototype generators at the Sandia test area. Experiments will be conducted to control the pH of the feedwater to the generator and thus influence the pH of the steam discharge.

Discussion

- Current laboratory work is directed towards exposing a greater range of materials to a variety of corrosive environments.
- Visual observations after tests conducted to date have not revealed any corrosion of the downhole generator itself.

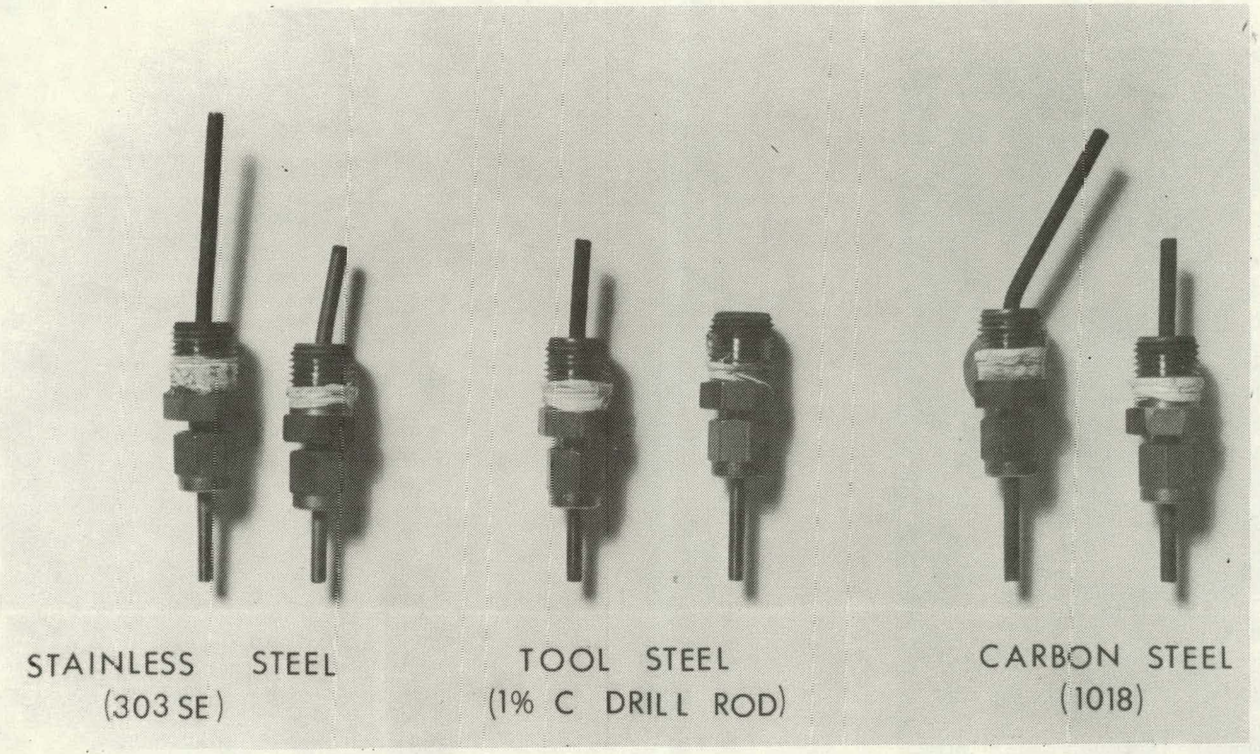
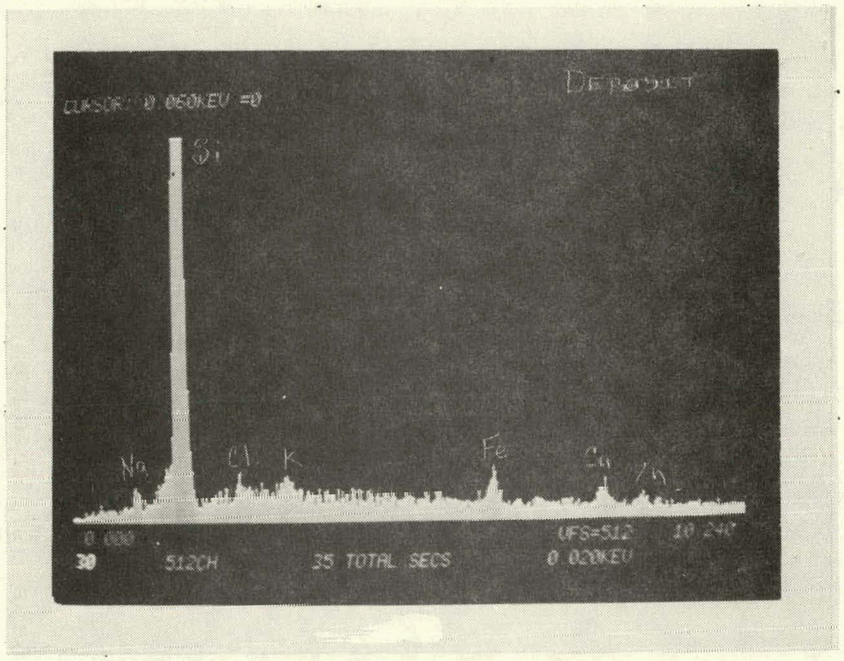
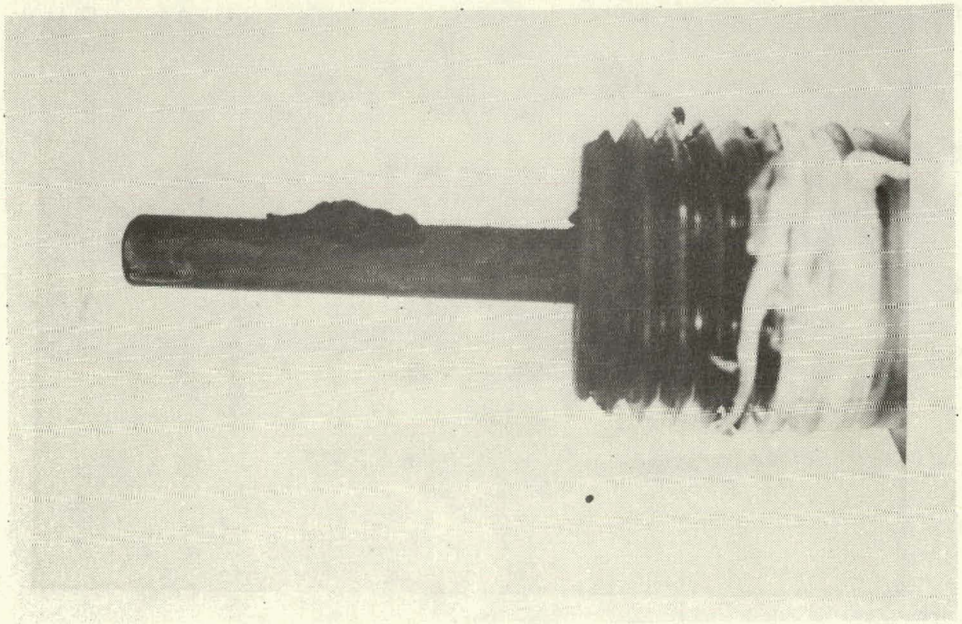


Figure 1. Materials Coupons after ~25 Days of Exposure to Mildly Basic Steam at 188°C, 340 psia

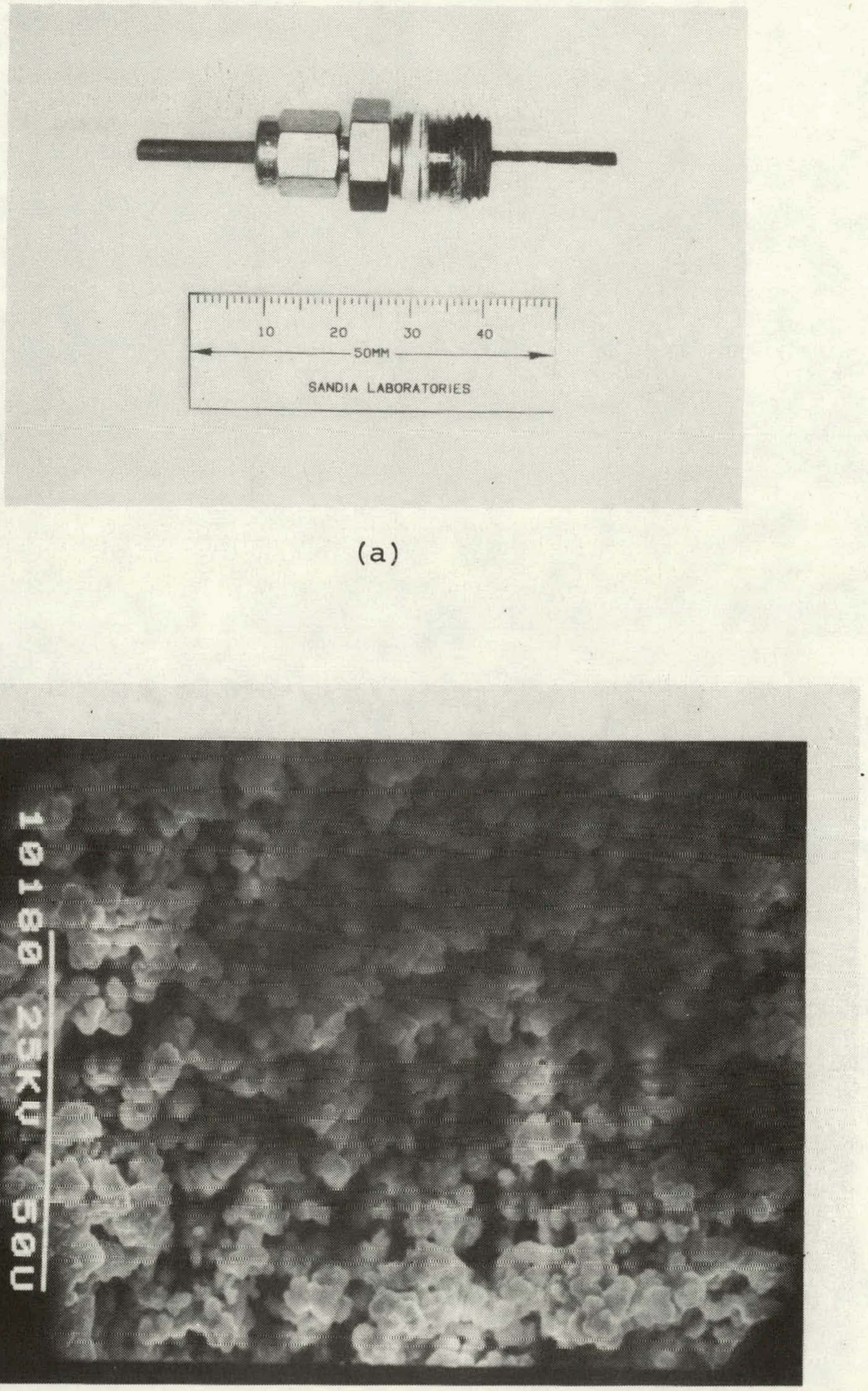


(a)



(b)

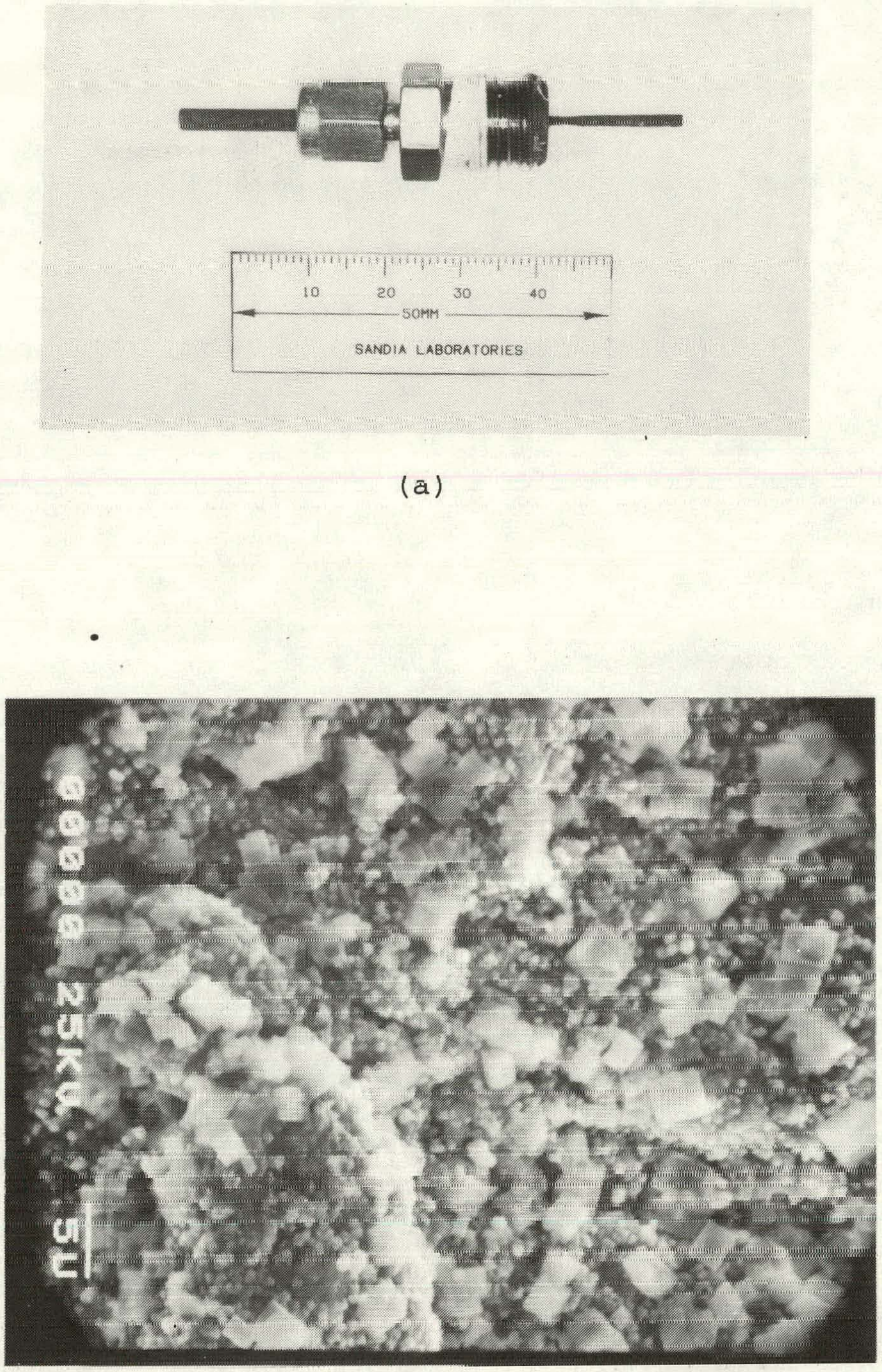
Figure 2. Silicon Deposit on 303 Se ss Sample: (a) Analysis of Deposit Components; (b) Photograph of Deposit



(a)

(b)

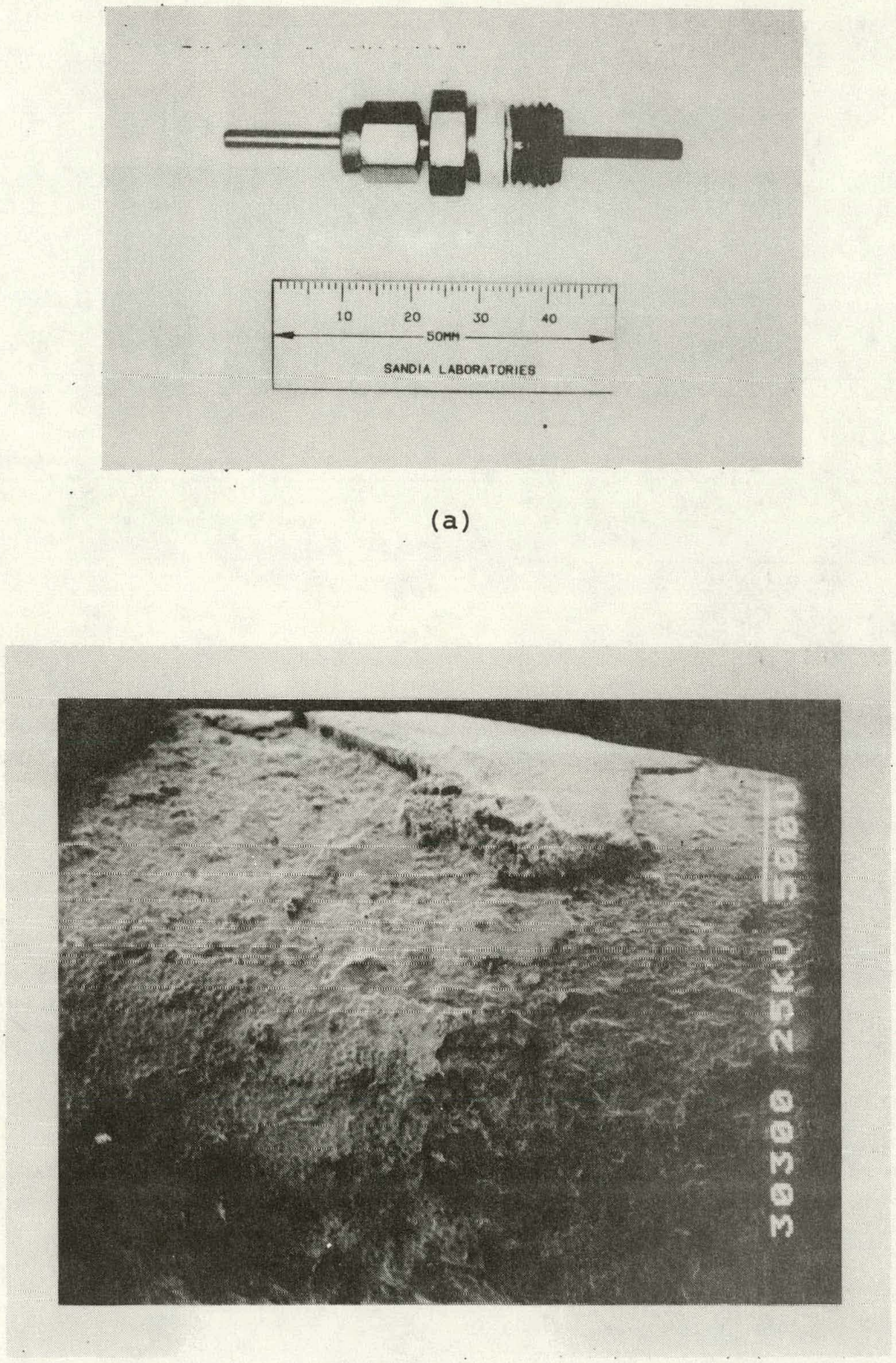
Figure 3. 1018 Steel Sample after Exposure to Mildly Acidic Steam



(a)

(b)

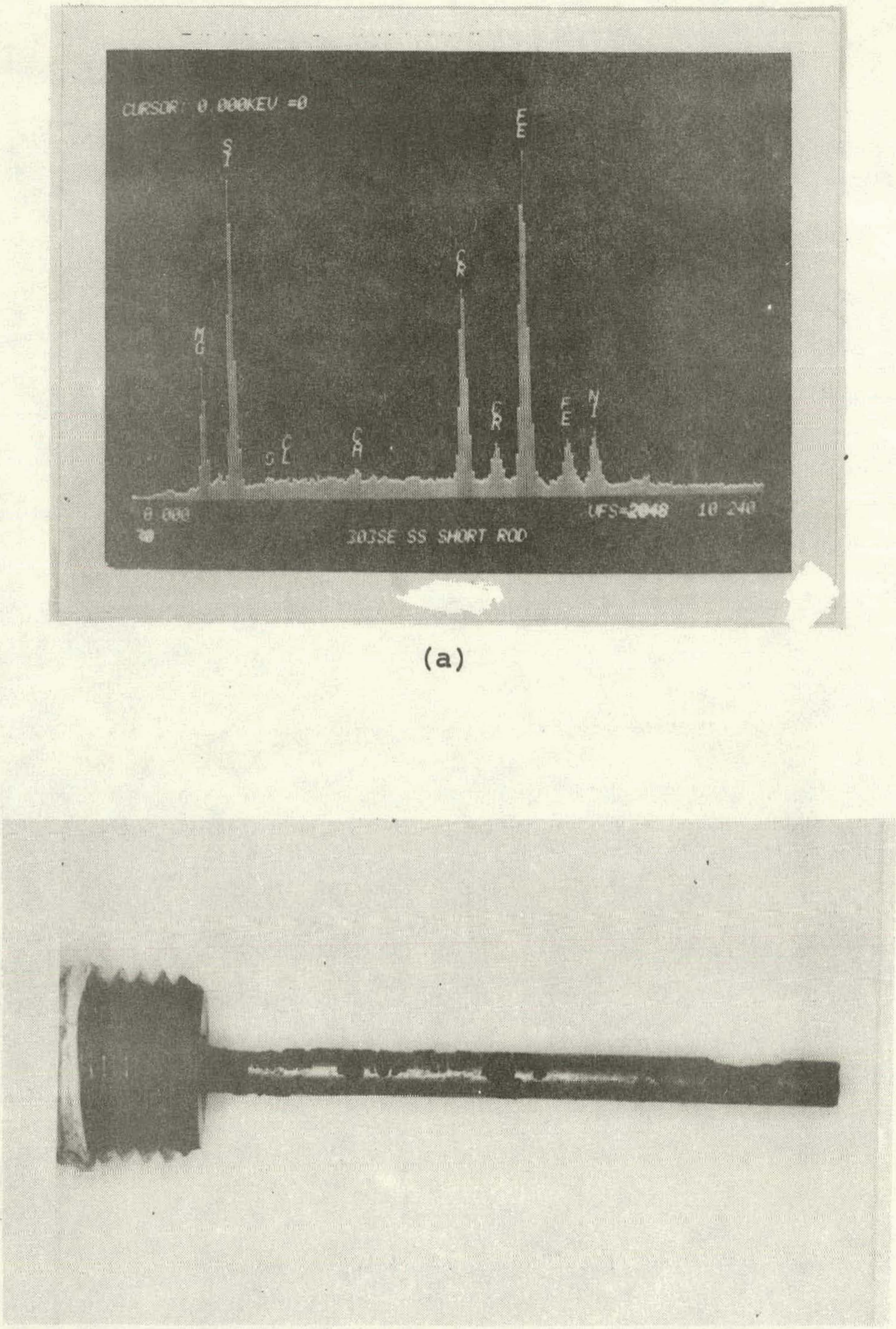
Figure 4. 1095 Steel Sample after Exposure to Mildly Acidic Steam



(a)

(b)

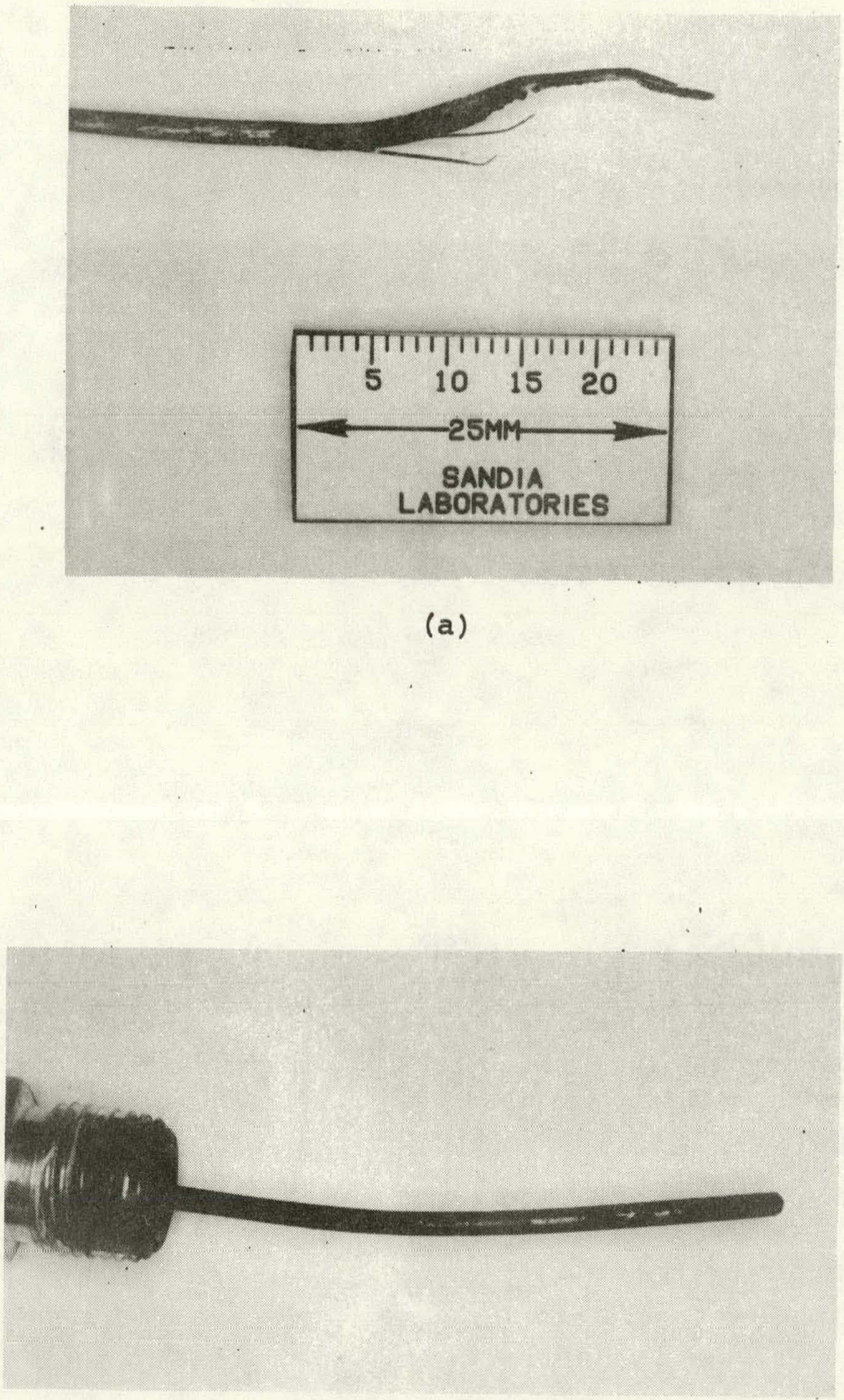
Figure 5. 303 Se Stainless Steel Sample after Exposure to Mildly Acidic Steam



(a)

(b)

Figure 6. 303 Se Stainless Steel Sample after Exposure to Steam with SO_2: (a) Post-Exposure Component Analysis; (b) Photograph of Corroded Sample



(a)

(b)

Figure 7. Chromel-Alumel Thermocouple after Exposure to Steam with SO_2

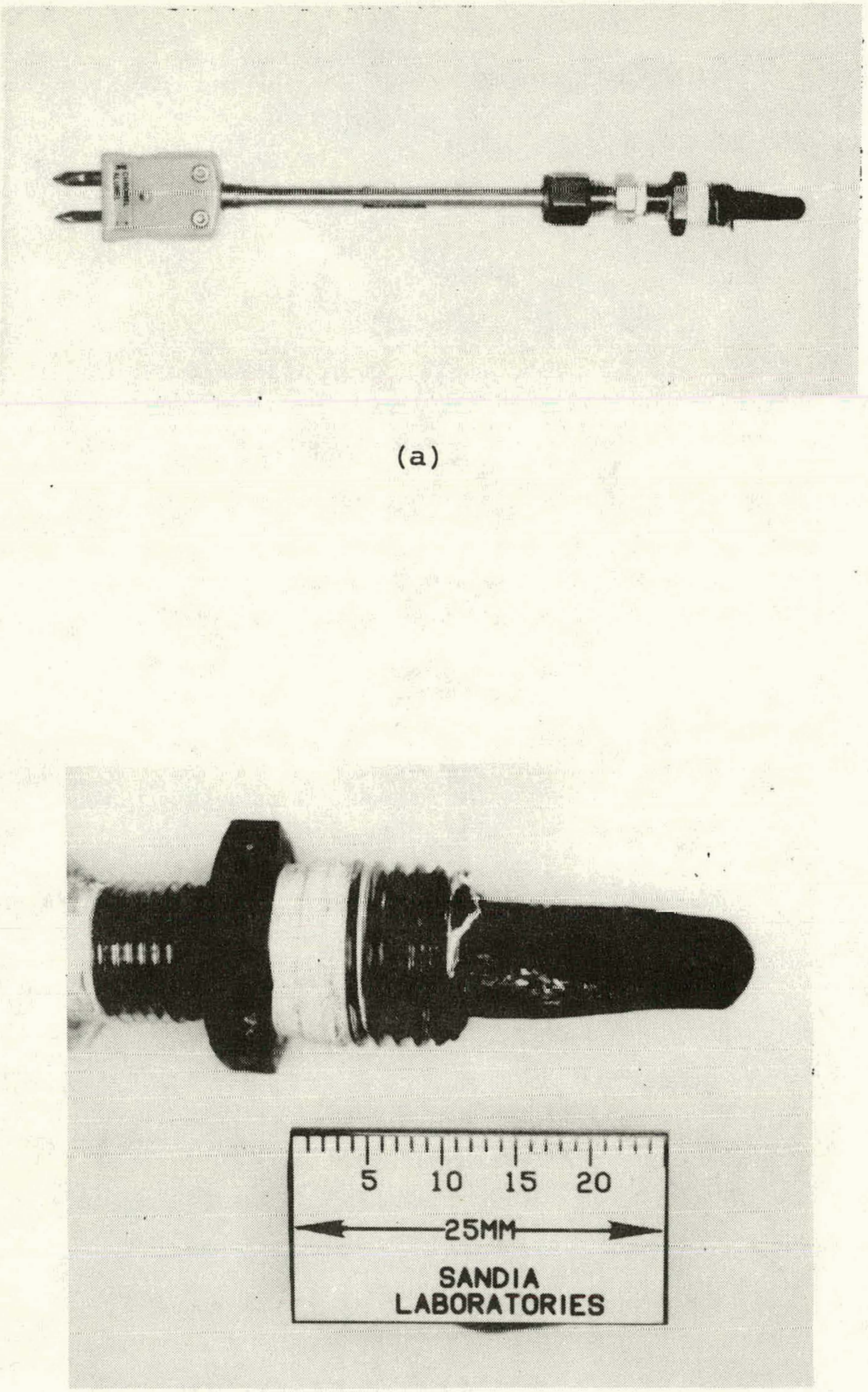
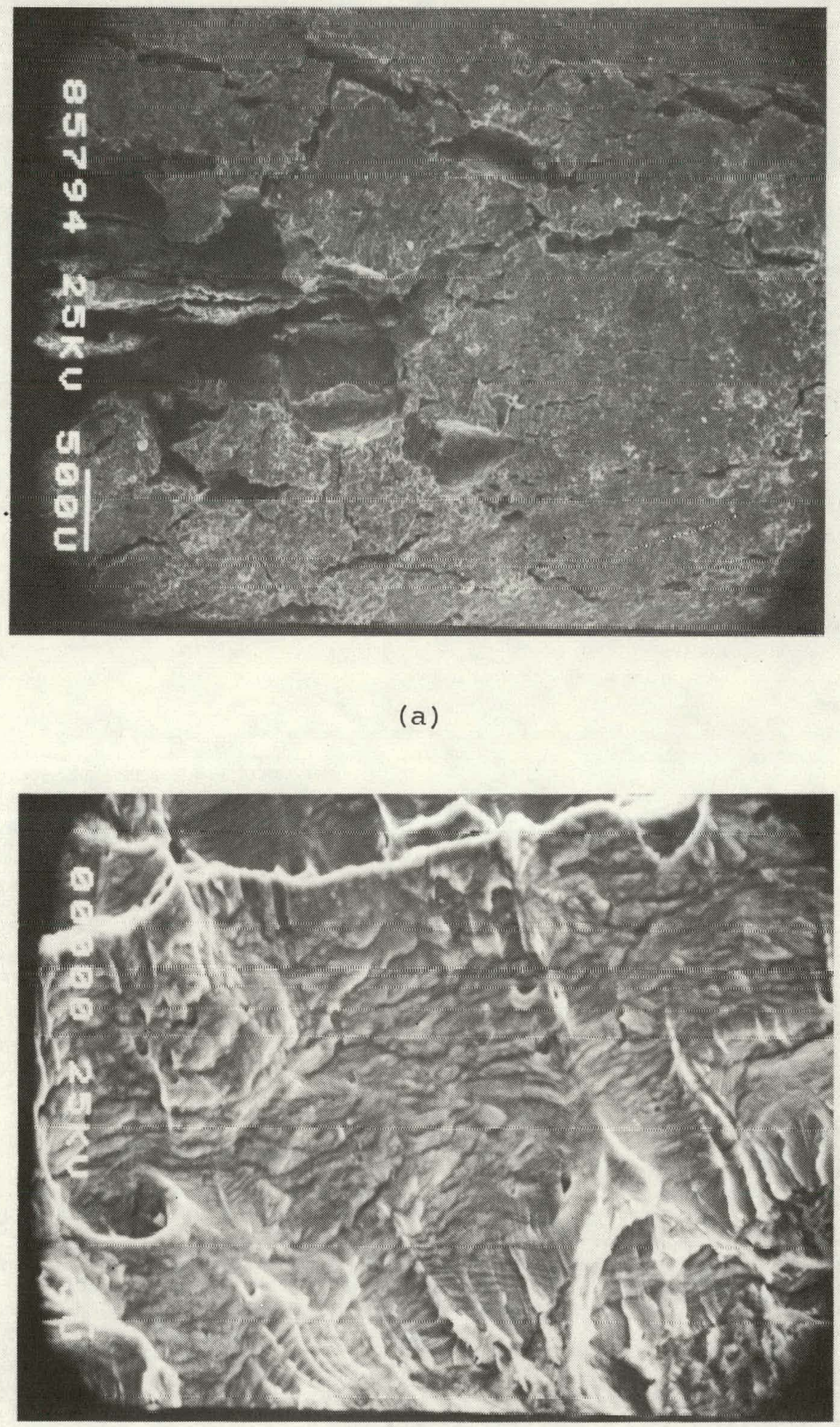


Figure 8. Chromel-Alumel Thermocouple after Exposure to Steam with SO_2



(a)

(b)

Figure 9. Electron Micrographs of Thermocouple Corrosion

MULTIPLE-STRING INSTALLATION TEST

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The multiple-string installation test at Hobbs, New Mexico, was conducted 22 through 24 September 1980. R. C. Ellis of the Completion Technology Company, Houston, located an ARCO well suitable for this test that was in the process of being abandoned. In exchange for use of the well, Sandia completed the abondonment process.

The demonstration test consisted of running an inert "worst case" generator and five strings to a depth of 2200 feet (670 meters). The strings were 2.375-inch o.d. EUE 8rd and 1.660-inch o.d. CS Hydril jointed tubulars, 0.375-inch o.d. and 0.250-inch o.d. continuous stainless steel tubulars, and a 0.461-inch o.d. electrical cable. The test string included a Baker HB packer. The generator included an instrument package which had a passive system for ignition and temperature measurement and an active multiplexed measurement system. Simple hand-operated reel stands were used to handle the continuous tubulars and electrical cable. Dual slips and elevators were rented, and the slips were modified to handle the continuous strings. All other equipment used for the test was standard oilfield equipment. R. C. Ellis acted as agent for Sandia and procured all the equipment and services required for the test.

The procedure followed during the test was as follows. The jointed tubulars were run singly and stood in the rig as doubles. The 2.375-inch string was hydrotested during this operation, and the 1.25-inch Hydril pins were wire-brushed and inspected to minimize the possibility of leaks. The inert generator (with electrical cable attached) was assembled with the packer and stood in the well. The continuous tubulars were attached next, starting with the first double lengths of jointed tubulars. The weight was carried by the 2.375-inch tubular, and the continuous strings were banded to the 1.660-inch tubular. After everything was in the well at 2200 feet (670 meters), the stainless steel tubing was terminated and flow tested. The 0.250- and 0.375-inch tubes were connected internally at the generator, which permitted circulation of water to establish the integrity of the tubes. The next step was to set the packer, which required a quarter-turn to unlatch a J-latch, a 20,000-pound (89 kN) pull for pack off, and four turns to release the slick joint.

The 2.375- and 1.660-inch tubes were valved to allow pressurizing the casing below the packer seal. The seal failed at first but sealed after holding a second 20,000-pound (2760-newton) pull longer than the first time. The continuous tubes again tested positive for both pressure and flow. The instrument package passive system (glow plus and temperature measurement) performed correctly. The active multiplexed system failed due to water intrusion through a cable splice (determined by a post-test inspection). The packer was released by two successive 30,000-pound (134-kN) pulls. The rebound at release was approximately 2 feet (0.6 meter). A continuous tube test indicated that no damage was done to the tubing, and the system was returned to the surface to complete the test. The hand-operated cable reels performed adequately for this weight, but significantly greater depths may require mechanical reels.

ADVISORY PANEL RECOMMENDATIONS AND DISCUSSION

The Advisory Panel made several suggestions to the entire committee during the final session of the meeting. These suggestions, and the discussion that followed, are summarized below.

General Recommendations

It was recommended that L'Garde be supported in their Min-Stress II packer development effort until a working model is ready. The panel stressed that L'Garde be aware of the packer's commercial appeal and that the company should consider approaching a packer manufacturer to begin the commercialization process.

Economic decisions and comparisons should probably be based on dollars per Btu of steam delivered at the sandface, the panel suggested. Other standards, such as dollars per Btu of energy from in-situ combustion or dollars per barrel of oil recovered, were seen as too dependent on unstable parameters.

It was felt that the current economic computer model, INTERCOMP, is not universal enough. By ignoring the oil recovery factor and limiting economic evaluations to dollars per Btu of steam, the economics of downhole steam generation can be more readily determined for any well-characterized reservoir. Further, more data are needed on the effects of exhaust gas injection on early recovery (and hence on overall recovery economics). The next field test at Long Beach should provide these data, which can be used then to update the economic model.

The Panel defined "long-term" testing at the next test as being longer than 4 months but probably less than a year. It was felt that

4 months should be enough time to prove the reliability of the downhole generator, and that if further funding became a problem, the operator at Long Beach may want to take over the testing, with instrumentation support from Sandia. The time frame for commercialization was also mentioned: depending on the success of the upcoming test, it was felt that 1986 would be the earliest that a commercial downhole steam generator (DHSG) could be expected on the market.

Sandia/Industry Roles in Project DEEP STEAM

Sandia National Laboratories' role in the future of enhanced oil recovery (EOR) programs was clarified. Sandia's strengths were seen to lie in the basic research areas of systems analysis/modeling, hardware development, instrumentation, and materials testing. It was suggested that Sandia place greater emphasis on in-house research in the following areas:

- Insulating tubing strings. It was felt that industry is presently carrying the load in this area of the project, and that Sandia's capabilities in materials evaluation would dovetail smoothly with increased testing of thermally efficient tubing.
- Gauging of heavy oils. Improvements in the basic technology are needed.
- Improving expansion joints in an insulated tubing string. Industry and Sandia have been testing off-the-shelf hardware. Some basic research into the problem is needed.
- Reservoir description. Improved multidimensional models are needed. Also, as EOR efforts increase, improved descriptive techniques are needed that will characterize a reservoir from "behind pipe," i.e., using existing, cased wells.

A discussion of government-sponsored EOR efforts disclosed some resistance from budgetary agencies to the continued funding of these efforts. A trend towards questioning the government's role in joint government/industry undertakings was examined. In examining this problem, the question arose as to the right time to make the transition to commercialization. There is no simple answer, of course: with the downhole steam generator, commercialization will involve widespread acceptance by oil companies that have already invested in other enhanced recovery processes. Also, while the DHSG itself may be simple by some standards, to an oilfield worker it will be an entirely new and uncommon piece of hardware.

A trend towards international cooperation in EOR was also identified. A recently developed program between the United States and Venezuela is now focused on defining mutual needs. The DHSG may play a major role in this and other co-operative ventures.

Field Test Results

Some general comments were made on the Bakersfield test results: this phase of the project answered questions on plugging, corrosion, and the interaction of NO_x with the reservoir. The results also helped in defining areas needing further study, including the effects of injecting steam only versus the effects of injecting flue gases along with the steam, the effects of injecting foaming agents along with the steam, and the effects of flue gas particle size on the effectiveness of the steam sweep. This final potential problem was seen to have possible beneficial effects as well: large particles could be helpful in selectively plugging a reservoir.

APPENDIX

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