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Petroleum and Natural Gas Engineering

Methods for Restoring Productivity to Gas Wells in the Clinton Sand of Ohio, a Laboratory and Field Experiment

A Thesis in

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CHAPTER I

INTRODUCTION

Reduction in productivity in oil and gas condensate wells because of paraffin plugging is a serious problem that many operators face. Many investigations had been conducted, and many methods have been developed to clean up the well bore, tubing and surface equipment from paraffin deposition, but not many studies exist in dissolving paraffin deposition within the propped fractures and the reservoir pore spaces.

The Clinton sand is a widespread oil and gas producing blanket sand which covers a good part of Ohio and Pennsylvania. Consolidated Gas Service Company, through their affiliate, East Ohio Gas Co., operate thousands of wells in this formation. Most wells completed in the Clinton sand, after a brief flush period of production, maintain low productivity over long periods of time. These wells produce some Penn Grade crude oil together with the gas.

It is felt that one cause of the low productivity is the recipitation of paraffin compounds from the oil into the fractures as well as in the well bore and well tubing. Another factor may be damage to the formation near the wells during drilling and completion. This study investigates experimental methods to stimulate the gas wells in this reservoir. The effect of different stimulation techniques such as solvents, heat and ultrasonic energy were investigated in the laboratory.

The second part of this investigation deals with the application of the most promising stimulation techniques based on laboratory studies, to a field test, which consisted of a control well (newly drilled for this purpose) and several offset test wells located close to the control well.

In the test wells a thermal stimulation was conducted. Pressure build-up and fall-off tests and back pressure tests were taken prior to the stimulation in order to evaluate the results of the experiment.

The use of ultrasonic energy was not considered practical for the present study since no suitable equipment is commercially available at this time.

Solvent stimulation techniques did not look promising enough to try in a field test.

CHAPTER II

REVIEW OF THE LITERATURE

The literature is abundant in papers and studies on paraffin problems and solutions. After surveying many of these papers the following classification can be made.

A. Basic Studies

- Theoretical Studies in Paraffin Deposits
- Laboratory Evaluations of Paraffin Inhibitors
- Laboratory Tests of Paraffin Deposition

B. Paraffin Deposition and Removal in Tubings

- Steaming Methods
- Rod Scrapers
- Chemicals
- Back Pressure Methods
- Intermittent Electrical Heating
- Compressed Air
- Plugging of Tubing with Wax and Scales

C. Removal of Paraffin from Sand Face

- Fluid Saturation Methods
- Hot Water Injection
- Steam
- High Test Gasoline
- Heat Generating Chemicals
- Chemical Solvents
- Softeners
- Combination of Chemicals with Vigorous Swabbing
- Hot Distillate
- Electric Heaters

D. Removal of Paraffin in Flow Channels and Formation

Precipitation During Fracturing

Combination of Heat and Solvent to Clean up Formation

Flow Channels

Sonic and Chemical Methods

E. Other Problems

Emulsification

Scaling

Operating Conditions of the Wells

Formation Waters

F. Economics of Projects

G. Organization and Evaluation of Theoretical and Practical Projects

Classification A, C, D, and G most directly have a bearing on the present investigation. Salient points from studies in these groups are outlined below.

R. J. Cole and F. W. Jessen (9) conducted laboratory tests to investigate the effect of the temperature gradients and wettability as regards the deposition of paraffin upon a copper plate. For this purpose the authors used an 8.09% paraffin-oil solution with a cloud point of 91°F. The melting point of the paraffin used was 145°F. Even though these experiments were conducted using a cell rather than a porous media, several interesting points can be noted. Because of the low thermal conductivity of the paraffin (0.00056 cal/cm/sec-°C-cm^2) when a film of paraffin is deposited, the overall thermal conductivity of the system (copper-paraffin or rock-paraffin) changes drastically. For example, Cole reports that to secure the same rate of heat conduction occasioned by a 10°F temperature differential across a plate with no paraffin deposition

would require an overall theoretical temperature differential of 104°F with a 1/16-inch film of paraffin on the plate. Initially, the paraffin is deposited because of the temperature drop at the free surface in the plate, while thereafter the overall heat conductivity becomes the controlling factor. They also noted that as the film of paraffin thickened, the temperature of the paraffin surface was increased greatly and the temperature differential between the solution and paraffin decreased with the thickness of the film.

To investigate the effect of surface wettability the copper plate surface was varied using silicone products, the resulting contact angles relative to water were measured. They found that even when a kerosene-paraffin solution wetted the plate surface, the free surface energy of the plates decreased with increased contact angles. Finally, they concluded that if enough water is present to completely cover the surface, there should be little if any paraffin deposition because of the very small interfacial tension between paraffin and water.

D. A. Shock, J. D. Sudbury, and J. J. Crocket (27) reviewed the literature on the paraffin deposition problems. They established the following factors to be the most important for the paraffin problems.

a. the chemical composition of the deposits,

b. the solubility behavior in the environment between formation and atmospheric conditions, and

c. the rate and nature of deposition.

Table 1 gives the possible compounds in the paraffin depositions. From their investigations they concluded that the normal paraffins are the principal constituents of crystalline waxes, and the branch chains form most of the microcrystalline waxes. Paraffin and wax depositions

are soluble in many industrial solvents, however the nature of crude oil and insoluble materials change the range of solubility of waxy material in the various solvents. Since the waxes tend to supersaturate easily if equilibrium conditions change smoothly and gradually no deposits build up. However, if the change is sudden, very rapid deposition takes place. Factors that tend to reduce the temperature of the fluid will cause the paraffin to precipitate. These factors could be the injection of cold fluids and the liberation of gas. Shock, et al (27) also pointed out that due to the greater specific heat of water, when water production increases, deposition in wells and lines decreases.

C. F. Parks (20) reported successful elimination of paraffin deposits using chemical inhibitors. J. J. Drener (10) published a paper reporting that in the Red Wash field, Utah, the following measures were successful in preventing paraffin depositions: bottom hole heaters, paraffin scrapers used in conjunction with rod rotation, hot oil treatment, steam phase line heaters, and electric heating cables. These two papers considered only the paraffin problem in the tubing, surface equipment and sand face.

G. Vail (29) and O. C. Dunn, Jr. (12) investigated the use of bottomhole heating devices to remove paraffin problems. Treatments of this kind maintain increased production over periods of time ample to justify the added workover cost.

F. B. Plummer (22) noted that the principal reasons for paraffin precipitation are: 1) loss of light fractions and gas from the oil, 2) temperature drop in the oil and (3) the presence of certain foreign matter in the oil around which the paraffin may precipitate. Of these three, the loss of gas and light fractions is considered the most important.

The paper published by Larman J. Health (14) discusses the improvement of gas well deliverability by the use of liquid rocket monopropellant, even though the paraffin precipitation problem was not considered in this paper, it is important to notice that this could be a powerful method for the removal of paraffin within the formation or in the fractures since he concluded in his study that it was feasible to burn the monopropellant within the interstices between sand grains.

In 1959, J. T. Rollins and L. C. Taylor (24) published the results of a new method to clean up formation flow channels using heat in combination with solvents. The procedure is as follows. A jelled oil carrying a suspension of magnesium pellets (20-60 mesh) is injected into the pay zone. Later, a fifteen percent hydrochloric acid solution is injected. The acid reacts with the magnesium pellets and liberates a large amount of heat (84,000 BTU/lb of magnesium). As a result the temperature of the formation may rise several hundred degrees. The spent acid is produced from the formation followed by the heated oil which pick up paraffin and asphalt deposits liquified by the liberated heat. They further suggest that it may be convenient to fracture the formation and inject the magnesium pellets into the fractures. They pointed out that large amounts of hydrogen are evolved from the chemical reaction, ($Mg + 2HCl - MgCl_2 + H_2$). Even though the hydrogen helps to kick off the well, the spent solvent may cause a fire hazard.

E. F. Bowers and H. Renfro (7), after investigating several methods for paraffin removal, concluded that the treatment of paraffin is an individual or areal problem. The composition and texture of the plugging determines the type of treatment to use.

Zaba (32) also investigated the reasons for paraffin deposition,

arriving at conclusions similar to those of Plummer (22). J. C. Wright (31), discussed paraffin prevention and removal in wells in Southern Ohio. Among other things, he concluded that the number of different compounds and types of waxes found in paraffin are dependent upon the character of the crude oil. The oil is mechanically held within the paraffin, trapped between the wax grains. As a consequence, a large amount of oil in paraffin tends to make it soft and semi-fluid, and more affected by heat regardless of the melting point of the wax present.

Among the causes for paraffin deposition he indicated the following as the most important: a) temperature, since the amount of paraffin an oil can hold is dependent in temperature up to the saturation point, b) losses of light fractions, c) transfer of heat from crude oil to pipe, d) presence of foreign particles to provide nuclei for paraffin formation and e) sudden drops in pressure.

One of the most interesting remarks made by Wright is that when gas is expanding it does work to push the oil out to the wellbore. A decrease in temperature then occurs. The pore spaces of the sand at the wellbore (and at the fractures) act as orifices and appreciable cooling at the face of the sand or fracture may occur when a high differential pressure exists between the two points under consideration. This could be a reason why many operators agree that the paraffin problems are worse in the early life of the reservoir when the reservoir pressure is high, since large drops in temperature occur where the gas is expanding. Finally, he discussed the different methods which may be applicable for solving the problem and preventing it.

J. C. Calhoun and S. T. Yuster (8) during saturation determination experiments found that erroneous oil saturations were being calculated

because of the presence of solid hydrocarbon within the sand sample. In their paper they discussed methods for determining the true oil and wax saturation. Like Wright (31), they agree that oil is being held within the crystals of the formed paraffin. The presence of paraffin will immobilize a good portion of the oil. The amount of oil immobilized will be a function of the distribution of the wax in the sand. As to the manner in which the solid hydrocarbons might have been deposited, they report the possibility of deposition by electrokinetic effect. According to this theory the amount of deposition must be some function of the flow, furthermore, they pointed out that other reasons for the deposition of wax could be lowering of temperature and pressure as well as the loss of light ends.

They found the amount of wax to increase directly with permeability, this could be done because of the electrokinetic effects due to the simple filtering action of the rock. If the rock with a larger permeability has a greater initial oil saturation, the amount of wax should be greater. This last statement is in good agreement with the experiments conducted by Cole and Jessen (9) where they concluded that the presence of water (connate water) reduces the amount of paraffin deposits.

Calhoun and Yuster determined the cloud point for several Pennsylvania crudes and found that the paraffin point of the crude (Gaines Crude Oil) and the temperature of the reservoir were identical, indicating that under these conditions the oil is wax saturated. This could be the case of many other fields with paraffin problems. Since the oil is saturated with paraffin, the smallest change in temperature, pressure or composition might cause paraffin precipitation.

Peters and Stout (21) investigated the prevention of formation

damage during fracturing of the Clinton formation. They mainly considered mechanisms of clay deposition.

Shutton and Roberts (28) studied theoretical and experimental considerations of reservoir cooling during fracturing and with formation damage that can occur if the temperature of the formation is lowered below the cloud point temperature of the crude oil in the reservoir.

The conclusions arrived by these authors are extremely important to the present investigation, for this reason they will be given:

a. From theoretical calculations, it was determined that cooling occurs throughout the propped or etched fracture when relatively large volumes of cold fracturing fluids are injected into low temperature example wells. If this cooling of the formation is below the cloud point of the reservoir fluids, formation damage can occur.

b. The thermal cooling adjacent to the fracture face was found to extend to a depth greater than 4 in. for the examples shown in this investigation.

c. The thermal recovery of the example wells was found to require more than 8 hrs. to achieve a ninety percent recovery of the original formation temperature.

d. The production of the example wells decreased significantly if the plugging of the formation adjacent to the fracture reduced the permeability to values of 10% of the original permeability.

e. From experimental results it was concluded that the smaller the initial permeability of the formation, the larger the damage due to paraffin precipitation. However, the lower permeability cores appear to recover faster under the conditions of the test.

f. The severity of paraffin damage increased as the temperature of the crude oil decreased below the cloud point of the oil.

g. In reservoirs with low bottom-hole temperatures that produce crude oil with high paraffin content, paraffin precipitation could be avoided by injecting fracturing fluids at temperatures higher than the reservoir temperature.

Practical and potential uses of ultrasonic energy have been thoroughly studied, applications have been found in medicine, geophysics, chemistry, and many other fields. The application of ultrasonic energy to a porous medium is reduced only to experimental types of procedures, mainly because of the technical limitation in designing a field-size tool.

Shoaf (25) studied the effect of ultrasonic upon a paraffin hydrocarbon in the presence of a cracking catalyst. From his investigation he concluded that the ultrasonic energy combined with the catalyst has an effect on the paraffin hydrocarbon. This effect was observed by aniline point depression, microphotographs of the compound and the reaction of hexadecane with concentrated sulfuric acid. He did not determine the reason for the effect.

Horblit (15) investigated the effect of ultrasonic energy upon the crystalization of wax from oil. Basically, what Horblit did was to subject samples of paraffinic oil to an ultrasonic energy field, and the yield and quality of the paraffin produced was compared to exactly duplicated samples where ultrasonic was not used. He observed an increase in yield under the influence of ultrasonic energy. However, he did not give the reason for such an increase. Further, it was found that the wax's melting point had changed. The increase in melting point, as well as

the increase in yield were found to be dependent on the frequency of the ultrasonic wave.

Duhon (11) experimentally investigated the effects of ultrasonic energy on the secondary recovery mechanism of oil production from a simulated petroleum reservoir. He compared simple water floods to a water flood where ultrasonic energy was used, the comparison was on:

1. Percent recovery of "sonic floods" as compared to the water floods.
2. The effects of these floods on such results as:
   a. instantaneous water-oil ratios
   b. relative permeability ratios

Duhon also investigated the basic characteristics of ultrasonic energy in a certain medium. As a consequence of his studies he arrived at the following conclusions. It is possible to recover additional oil from a sonic flood. The initial oil saturation had no effect upon the overall recovery. Water-oil ratios decreased mainly because of better mobility ratios. These smaller mobility ratios were originated by definite reductions in permeability ratios. Viscosity of the fluid was also important, oils with lower viscosities had higher percentage recoveries. The injectivity of a particular fluid was increased. Cavitation had a positive effect of oil production.

Komar (16) conducted experiments removing paraffin from a porous media using ultrasonic energy. He found that complete removal of paraffin was possible only in rocks with permeabilities larger than 500 md. He attributed the removal of paraffin from the porous media to the agitation of the paraffin solvent.

Laughton (18) investigated the occurrence of cavitation in solu-

tions of high polymers which are being irradiated with ultrasonic waves. He found that these solutions were degraded when exposed to ultrasonic waves with frequencies of 300 to 800 Kc/Sc.

Komar and Moore (16) performed oil recovery tests with ultrasonically formed emulsions. They formed dynamically stable emulsions capable of passing through a porous medium, provided that the minimum pore diameter is greater than the diameter of the dispersed droplets. The effect of ultrasonic was to reduce the size of the droplets.

Rigs and Brownscombe (23) reported the use of a sonic shock tool to remove wellbore flow barriers. A high-voltage current is discharged across electrodes which are immersed in well fluids. This discharge is so rapid that all the energy is stored before appreciable losses can occur. The high degree of molecular breakdown and ionization of the arc results in a plasma with an instantaneous temperature of 50,000°F which leads to pressures of the order of 150,000 psi of a microsecond duration.

Even though the principle of operation of this tool is different than an ultrasonic tool, it is another possible way to remove plugging around the wellbore.

The theoretical considerations of the ultrasonic energy behavior and effects on a porous media has been considered and studied by many investigators (3), (6), (4), and (5). The theories formulated have been extended from theoretical analyses of wave propagation in a homogeneous solid to heteroegeneous fluid saturated mediums. Some of these aspects will be discussed in more detail in another section of the present study.

TABLE 1

Possible Compounds in Paraffin Deposition

After: D. A. Shock, et al(27)

	Empirical Formula	Melting Point of	Boiling Point of
Paraffinic Normal	$C_{26}H_{54}$	133.2	401.0
Branch	$C_{26}H_{54}$	69.4	383.
Napthenes	$C_{26}H_{52}$	118.2	413.6
	$C_{26}H_{48}$	94.1	418.1
Aromatics	$C_{26}H_{46}$	108.1	413.6
	$C_{26}H_{46}$	61.5	384.0
Asphaltenes	$C_{24}H_{28}$	-	-
	$C_{22}H_{22}S$		

CHAPTER III

STATEMENT OF THE PROBLEM

The apparent cause of low productivity in some gas wells completed in the Clinton Sand of Eastern Ohio is the precipitation of paraffin hydrocarbons from Penn Grade crude oil which is being produced along with the gas. The paraffins appear to precipitate in the hydraulic fractures (made when completing the wells) as well as in the wellbore circuitry and in the production tubing.

The first step in analyzing the problem is to conduct laboratory experiments in the following stimulation methods to determine the most suitable for a field size project.

a. Investigate the formation of paraffin precipitates by studying variations in cloud point temperature of different paraffin-oil solutions.

b. Investigate the effect of different commercially available solvents in dissolving paraffin plugs in cores.

c. To study the effect of ultrasonic energy to displace paraffin deposits, this study will consider the effect of ultrasonic energy in the reservoir fluids.

d. To investigate the effect of temperature in the Clinton Sandstone as well as in Oriskany Sandstone cores. Improvements in permeability to fluids because of microfracturing of the rock matrix will be studied as well as the possible effects of wettability changes on the flow of gas and oil in the reservoir rock.

From the results obtained in the laboratory, the most attractive stimulation method was tested in field trials.

CHAPTER IV

DESCRIPTION OF THE LABORATORY EQUIPMENT AND EXPERIMENTAL PROCEDURE

Preparation of the Cores for the Different Experiments

Three types of sandstones were used in the experimental work. They were Berea sandstone, Clinton sandstone and Oriskany sandstone. The first sandstone, due to its widespread use, is the most well-known to the investigators.

The purpose of the present investigation was to study the behavior of the fluids within the Clinton sand, but because of the extremely low permeability of this sandstone, it was considered necessary to use the Berea and Oriskany sandstone in some cases.

The Clinton sandstone came from a core, taken from the newly drilled control well by Diamond Research Inc. It was necessary to drill smaller cores from it in order to perform permeability measurements. Using a diamond drill bit, cores having 3/4 inch diameter were drilled and cut to the desired length using a rock saw.

Berea samples came from the quarry already cut to a diameter of 2 1/8 inch and lengths of 1 and 2 ft. These cores were used in the ultrasonic energy stimulation experiments and it was necessary to prepare them for mounting in steel core holders. Berea sandstone was also used in the solvent stimulation experiments.

The Oriskany cores were already cut to the desired dimensions - 3/4 inch diameter and lengths from 1/4 inch to 3/4 inch. These cores were used in the solvent stimulation experiments as well as in the thermal stimulation studies.

Cloud Point Determination System

To conduct the different experiments, it was necessary to prepare reproducible paraffin-oil solutions, as well as to clean up the impurities in the paraffin and oil samples obtained from the stock tanks from the reservoir under study. Once clean paraffin and oil were available, samples of 5, 7, 10, 15 and 20% paraffin-oil solutions were prepared to determine the cloud point of these solutions, a constant temperature bath was used to maintain a range of temperature from 50°F to 150°F. Viscosity measurements were taken using an Oswald viscometer. Temperature was decreased at intervals of 10°F.

Solvent Stimulation System

The system (Figure 1) consists of three main components, a Hassler sleeve, a reservoir for fluids and the volume recording apparatus. The system was placed inside a natural convection oven to maintain a constant temperature, and to perform the desired changes in temperature.

The Hassler sleeve consisted of a core holder, the sleeve and the pressurizing-vacuum system. With two manifolds strategically located it was possible to pull a vacuum to remove the core and to pressurize the sleeve while conducting experiments.

The Hassler sleeve was pressurized using a Ruska pump, which displaced silicone oil into the sleeve to produce the desired pressure.

Vacuum was created with a duo-seal vacuum pump.

The reservoir fluid was connected to a nitrogen tank, which supplied the displacing energy to flow the different fluids (water and oil) through the core.

The system has a bypass, which was used to perform measurements of gas permeability, simply by closing the manifold to the reservoir fluids,

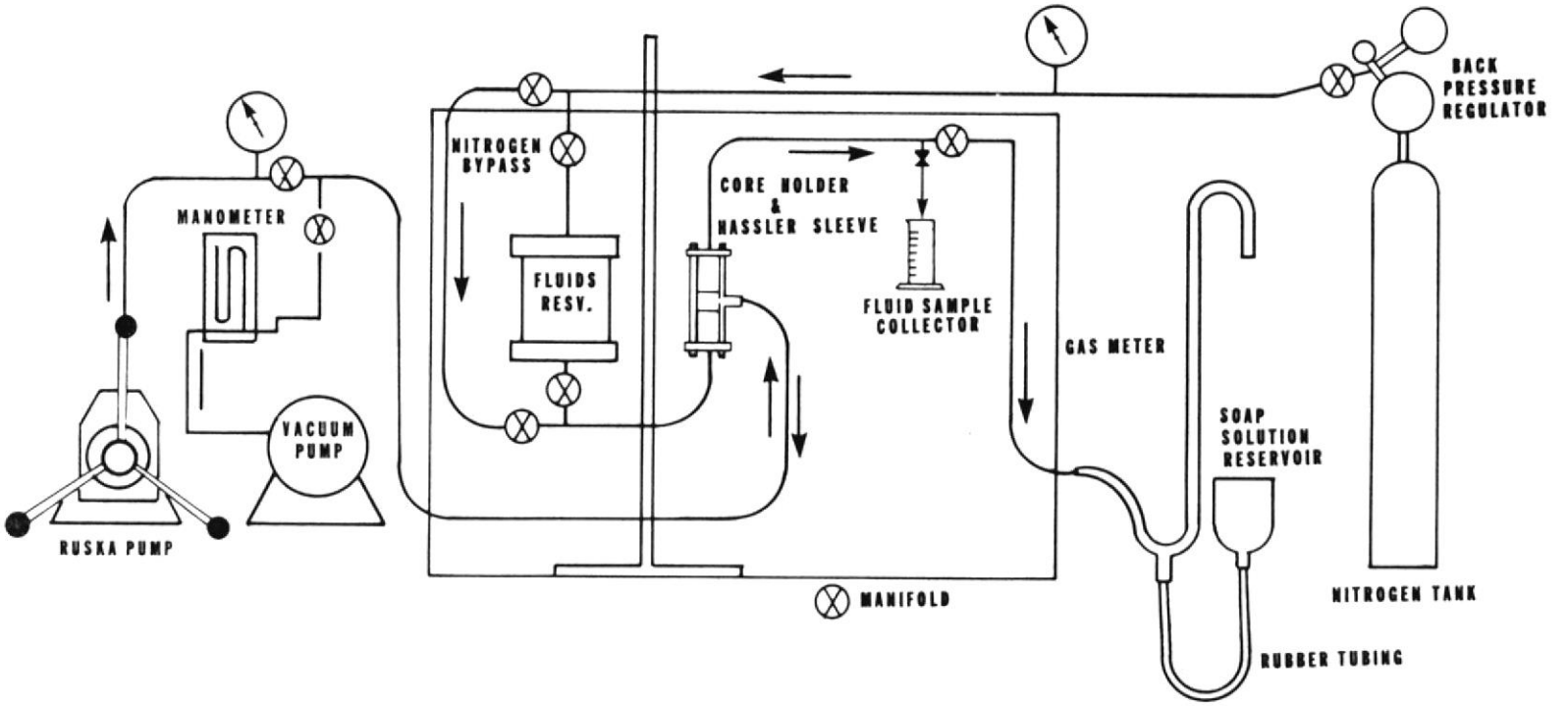


Figure 1. Solvent Stimulation System

and forcing the nitrogen through the bypass into the core.

The volume recording apparatus consisted of a graduated cilinder, sample collector and a gas "bubble" flow meter. The bubble meter works as follows. A glycerine-water-soap solution is placed into the solution reservoir, the bell is raised and lowered in order to introduce fluids to the line, the gas which is coming from the core bubbles through the soapy solution and displaces bubbles of soap up through a sealed glass burette. The time that it takes a bubble to travel from the 0.0cc level up to 25cc level is recorded.

A number of common solvents were tested on paraffin samples to identify those which would completely dissolve the samples in beakers with only gentle stirring. Five solvents which passed this test were chosen for flow experiments in Berea cores. They were:

1. Naphtha
2. Gasoline
3. Toluene
4. Carbon tetrachloride
5. Kerosene

Five separate Berea cores were used for the experiments ensuring that the results were not affected by cleaning procedures. The general procedure used for these solvent runs was as follows:

1. After drying at 100°C overnight, the cores were saturated with 2% NaCl brine.
2. The permeability to the oil (Sandy Lake #3 crude with 0% paraffin in solution) was then measured at room temperature (80°F). All flow tests were done using a constant pressure drop.

3. The temperature of the entire system was then raised above the cloud point of a 7% paraffin crude mixture to 100°F in a large oven.
4. The paraffin-crude mixture was then displaced through the core and its permeability measured during this period.
5. The system was then cooled below the cloud point of the 7% paraffin-crude mixture to room temperature (80°F).
6. Paraffin free crude was injected again. In most cases the cores were completely plugged and no flow was measured.
7. Essentially three pore volumes of solvent was injected into the core.
8. Paraffin free oil was again injected and the permeabilities determined. When no further increases were evident the run was considered complete.

Permeability Measurements of the Different Cores Used

Plugging in the cores was determined by the reduction in permeability observed during the different experiments.

Two instruments were used to determine permeability in these cores. The first was the system described in the solvent stimulation system. The second was a Ruska permeameter, used to determine the absolute permeability of the dry cores.

The general procedure was as follows:

1. Cut the core from the larger cores obtained from field samples or directly from the quarry.
2. Extract the cores following the ASTM extraction method.
3. Place the cores in an oven at 100°C and dry them overnight.

4. After drying, place the cores in a vacuum cell and extract for 1 hr.
5. Saturate with water (for water-wet rocks) or oil (oil-wet rocks).
6. Place the core in the Hassler sleeve system and start the measurements.

When the cores were water-wet, the permeability to water was determined first, then the permeability to oil and finally the permeability to gas. All these measurements were performed using the solvent stimulation system.

Ultrasonic Stimulation System

Figure 2 shows the system used in the ultrasonic energy experiments. As in the solvent stimulation system, the displacing energy was nitrogen from a nitrogen tank.

A manifold system was set up in such a way that it was possible to inject water, oil and paraffinic oil in the required sequence. Berea cores were mounted in robust core holders. At the outlet an ultrasonic energy probe was attached, and the system was placed in a natural convection oven.

The liquid samples were collected in an interval sample collector, the collector was connected to a clock.

The energy for the ultrasonic probe was regulated by a control panel. Once the core was properly mounted, the system was closed and the core was evacuated for 2 1/2 hrs. (long cores) and 1 1/2 hrs. (short cores). Then the core was saturated with water and the permeability to water (kw) was measured. Once a stabilized flow of water was obtained,

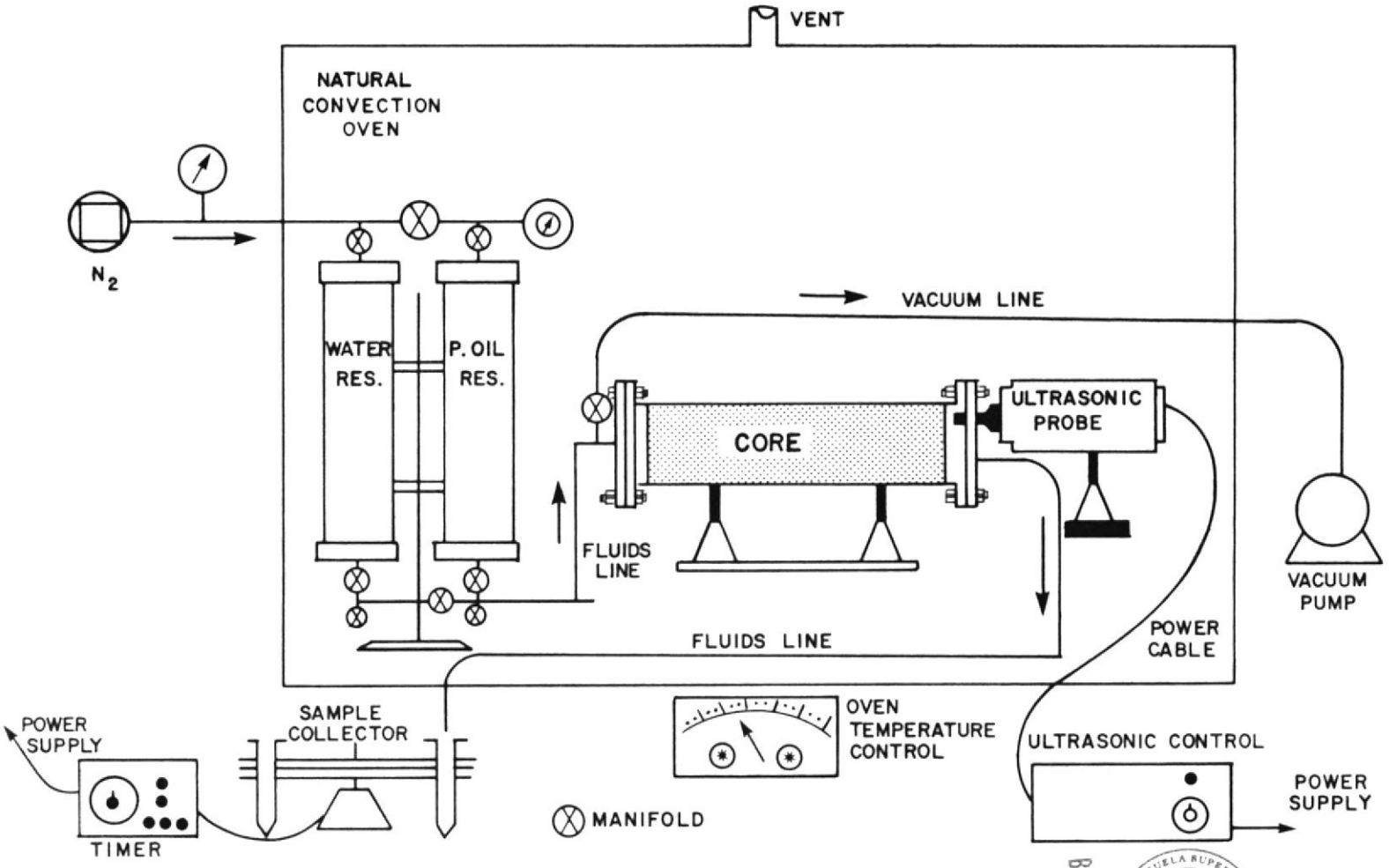


Figure 2. Ultrasonic Stimulation Apparatus

the reservoir fluid was changed from water to oil (with 0% paraffin) and oil was forced into the core. Again, once the flow of oil was stabilized, its permeability, (k_o) was determined and the oil was changed to 10% or 20% paraffin oil (depending upon which set of runs was in progress). The temperature of the oven was raised to 100°F (above the oil cloud point) and the paraffinic oil was injected in the desired amount (the size of the slug was different in every case). The injection of paraffinic oil was then stopped and the temperature of the system was lowered to 80°F (well below the cloud point). Once the temperature was 80°F, the injection of 0% paraffin oil was again started. In every case it was decided to wait 2 hrs. (while exerting a pressure of 30-50 psi with the displacing oil) before starting stimulation with ultrasonic. In all the cases investigated the permeability to oil was reduced to zero by the precipitated paraffin. Stimulation with the ultrasonic varied from 1/2 - 1 hr.). Once the flow of oil was stabilized, or the flowing time was too long and the increases in permeability were small, the run was stopped and a new run with a fresh core was initiated.

Wettability Change and Thermal Stimulation Experiments

To perform the wettability change experiments, the solvent stimulation system was used. The procedure to study wettability changes was as follows:

1. Clean, dry at 120°C and evacuate the core. Saturate it with 2% NaCl brine so that the rock is water-wet.
2. Measure the relative permeability to water, oil and gas by flowing these fluids through the cores and measuring the pressure drops.
3. Clean, dry at 120°C and evacuate the same core. Saturate with

Sandy Lake crude oil so that it was oil-wet.

4. Measure the relative permeability to oil, water and gas by flowing these fluids through the core and measuring the pressure drops.

To study the effect of temperature in the cores the procedure was as follows:

1. Clean, dry at 120°C and evacuate the core. Saturate it with 2% NaCl brine so that the rock is water-wet.
2. Measure the relative permeability to water, oil and gas by flowing these fluids through the cores and measuring the pressure drops.
3. Clean, dry at 120°C and evacuate the same core. Saturate it with Sandy Lake crude oil so that it was oil-wet.
4. Measure the relative permeability to oil, water and gas by flowing these fluids through the core and measuring the pressure drops.
5. Take electron microscope pictures of these cores.
6. Bake the cores at 1000 - 1200°F using a heavy duty furnace.
7. Repeat steps 1-5.

In this way it was possible to study not only the alternation of the rock but the possible gains due to wettability changes which might occur.

CHAPTER V

DISCUSSION OF EXPERIMENTAL RESULTS

Cloud Point Determination

When originally discovered, hydrocarbons are in a state of physical and chemical equilibrium. When production starts, this equilibrium no longer exists and the fluids and the rock undergo a series of chemical and physical changes. Furthermore, when a cold fluid (fracturing fluids, for example) is introduced in the formation, even more drastic changes occur within the reservoir.

If the changes in pressure and temperature are large enough such that the cloud point of the fluids is reached, the paraffin which is in solution will begin to precipitate in the tubing, flow lines, as well as within the fractures.

To study the effect of temperature (since the viscosity of the fluid is largely affected by drastic changes in temperature) solutions of 5, 10, 15 and 20% (paraffin-oil) were prepared and the change in cloud point studied.

Figures 3 to 6 show plots of ln. viscosity versus temperature (in °F, and reciprocal of degree Rankine). This method of determining the cloud point is based upon viscosity characteristics. The relationship between temperature and viscosity is of the following type.

$$\mu = Ae^{\frac{B}{T}} \quad \text{(Andrade's equation)} \qquad 5.1$$

or

$$\log \mu = \log A + \frac{B'}{T} \qquad 5.2$$

where μ = viscosity, centipoise

T = absolute temperature, °R or °K

A, B', m, B = constants

A has the same order of magnitude as viscosity

B is approximately equal to the heat of fussion divided by the gas constant (12).

Experimental data have verified the above equation, and it is quite accurate for liquids.

Now, when viscosity of a crude oil is being measured, the relationship must be linear as long as oil is a homogeneous fluid. As soon as any solid matter forms and is suspended in the liquid a deviation from the linear behavior must be evident. The point of departure must be that at which the oil is saturated with the solid hydrocarbon, i.e., paraffin point.

In Figure 3 it can be noticed that the departure from linearity is rather smooth, while in the other cases, 10, 15 and 20%, (Figures 4, 5 and 6) the departure is sharp. This is due to the existence of colloidal particles in the 5% case, while in all the others, the sharp break indicates the precipitation of larger wax particles.

From these experiments it could be said that paraffin plugging may be expected for any oil having paraffin in solution if the condition of temperature and pressure are such that the large decrease in reservoir temperature takes the fluid to points below its saturation temperature. Once the paraffin is precipitated, it is almost impossible to regain the original permeability, until the temperature is raised to a point above the melting point of the paraffin. This was observed in the present study. It was observed also, that the cloud point temperature increases with increasing paraffin concentration in the oil, this is considered normal behavior.

The increase of cloud point temperature with increasing paraffin concentration was found to be a straight line as depicted in Figure 7.

TABLE 2

Temperature and Viscosity Data for a 5% Paraffin-oil Solution

TEMPERATURE (°F)	DENSITY (gm/cc)	VISCOSITY (cp)
150	0.7911	2.8071
140	0.7946	3.1132
130	0.7087	3.4517
120	0.8020	3.8627
110	0.8062	4.3896
100	0.8115	5.1589
90	0.8162	6.1855
80	0.8182	7.5364
75	0.8197	9.2118
70	0.8210	11.3278
60	0.8222	21.4546

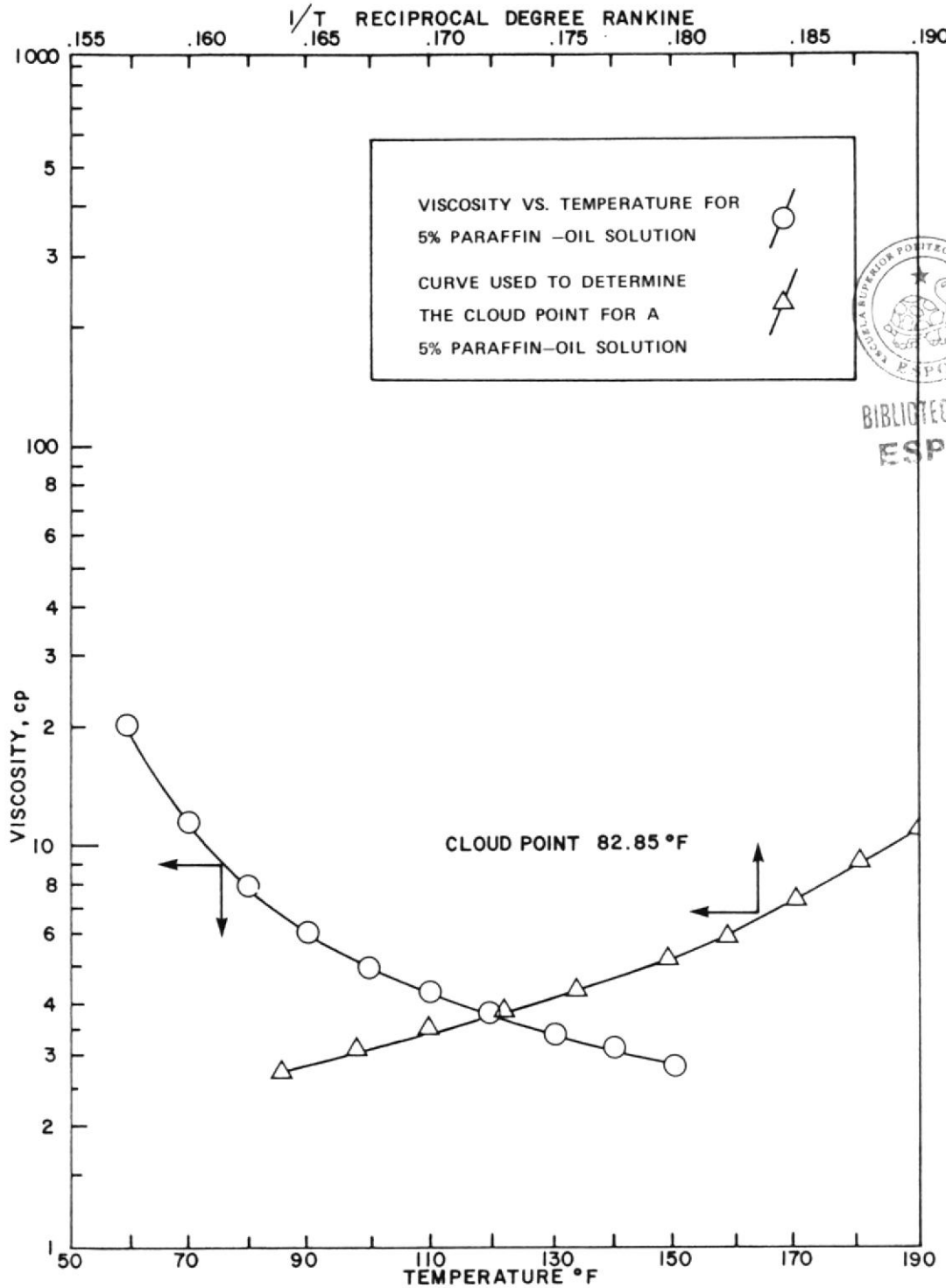


Figure 3. Viscosity vs.Temperature for 5% Paraffin-oil Solution

TABLE 3

Temperature and Viscosity Data for 10% Paraffin-oil Solution

TEMPERATURE (°F)	DENSITY (gm/cc)	VISCOSITY (cp)
150	0.7898	2.7855
140	0.7955	3.1252
130	0.7992	3.4837
120	0.8028	3.9137
110	0.8067	4.4109
100	0.8104	5.0259
90	0.8143	6.1872
80	0.8179	10.3859
75	0.8203	17.3508
70	0.8223	33.4676

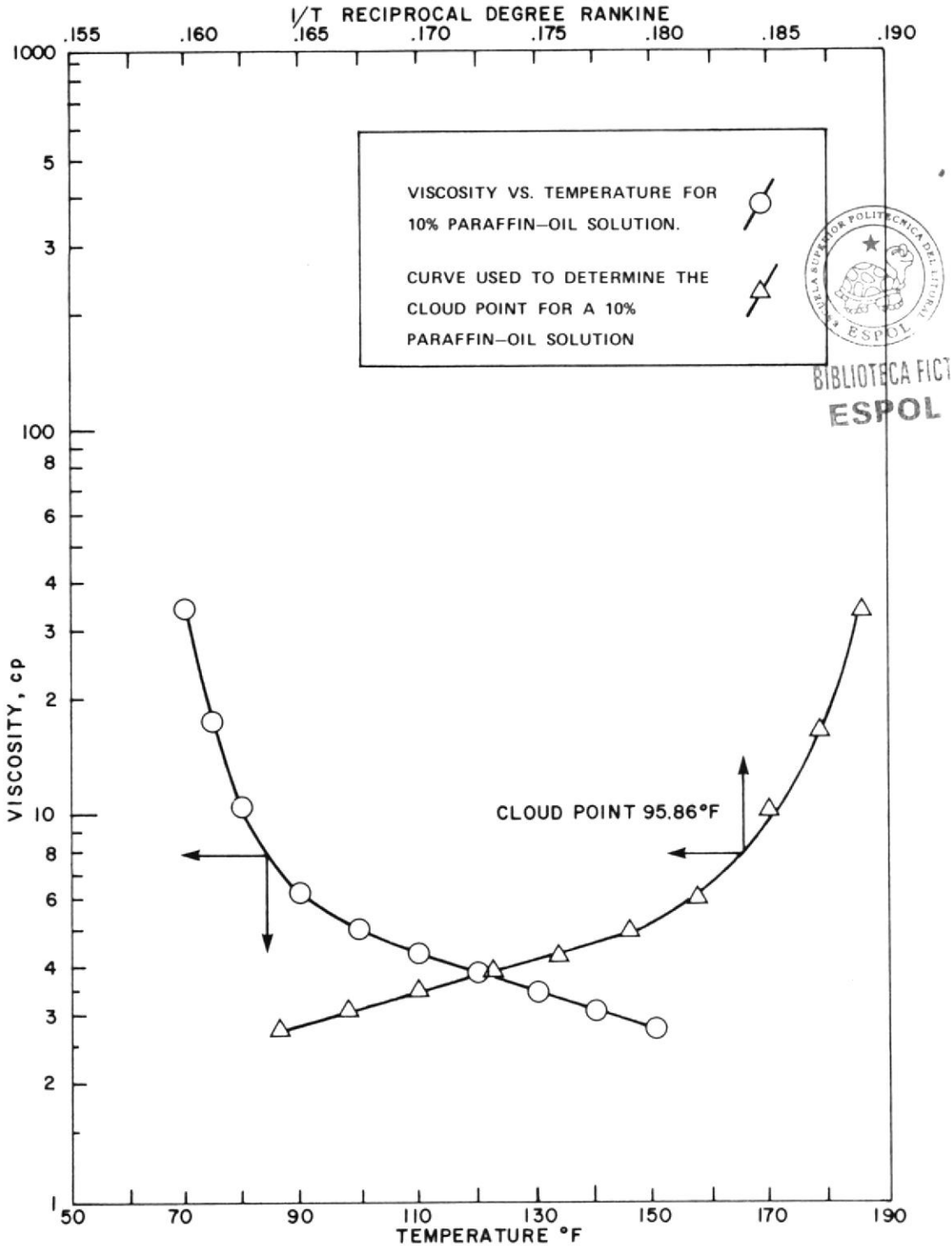


Figure 4. Viscosity vs. Temperature for 10% Paraffin-oil Solution

TABLE 4

Temperature and Viscosity Data for 15% Paraffin-oil Solution

TEMPERATURE (°F)	DENSITY (gm/cc)	VISCOSITY (cp)
150	0.7929	2.9521
140	0.7972	3.2785
130	0.8005	3.6594
120	0.8044	4.1125
110	0.8083	4.8469
100	0.8122	5.3257
90	0.8164	7.1275
80	0.8204	13.2231
70	0.8248	34.5194

TABLE 5

Temperature and Viscosity Data for 20% Paraffin-oil Solution

TEMPERATURE (°F)	DENSITY (gm/cc)	VISCOSITY (cp)
150	0.8050	3.5923
140	0.8092	4.0937
130	0.8122	4.5918
120	0.8160	5.0854
110	0.8202	5.9347
100	0.8244	7.4711
90	0.8283	11.5060
80	0.8317	20.5177
70	0.8321	41.5916

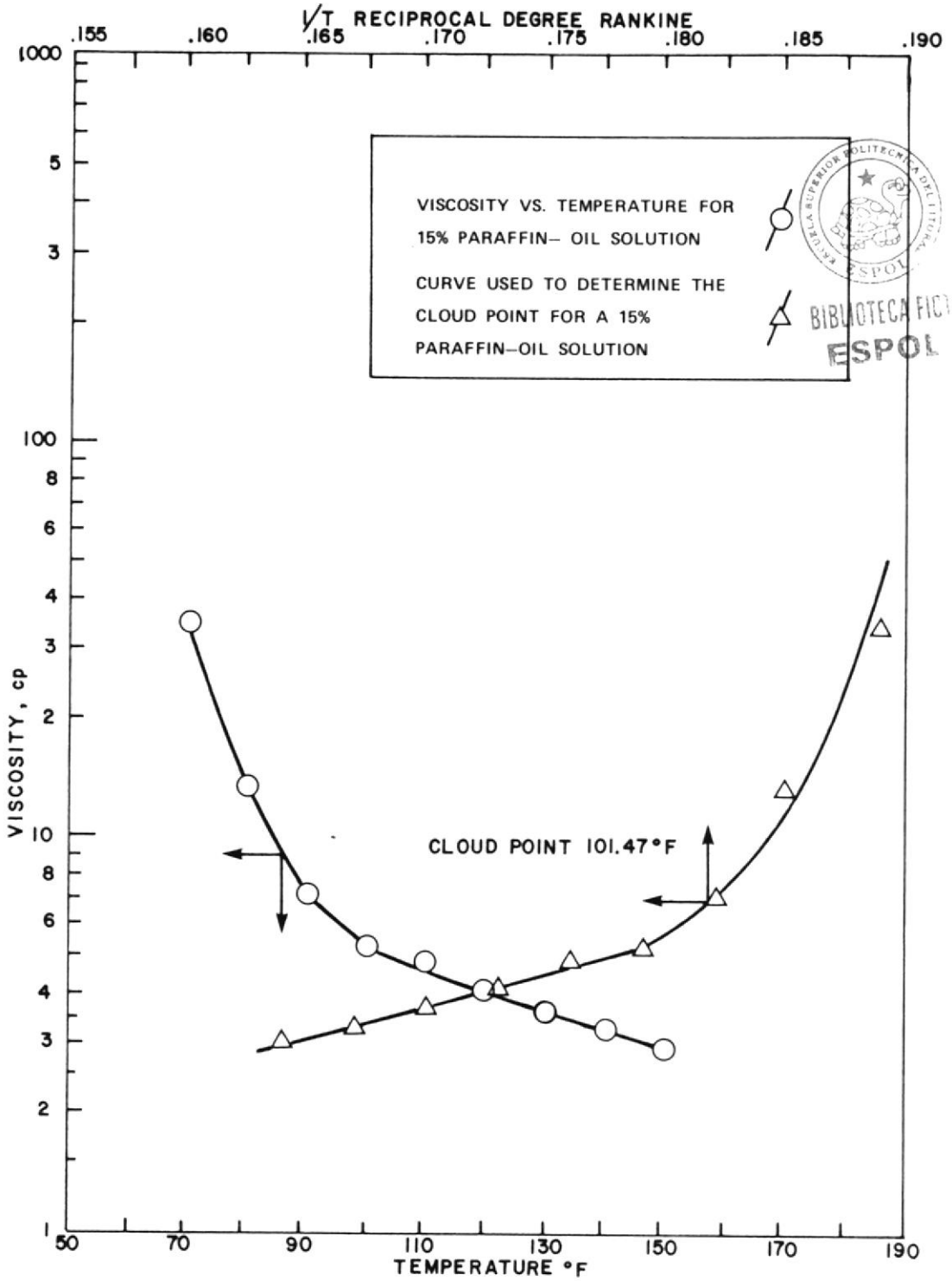


Figure 5. Viscosity Vs. Temperature for 15% Paraffin-oil Solution

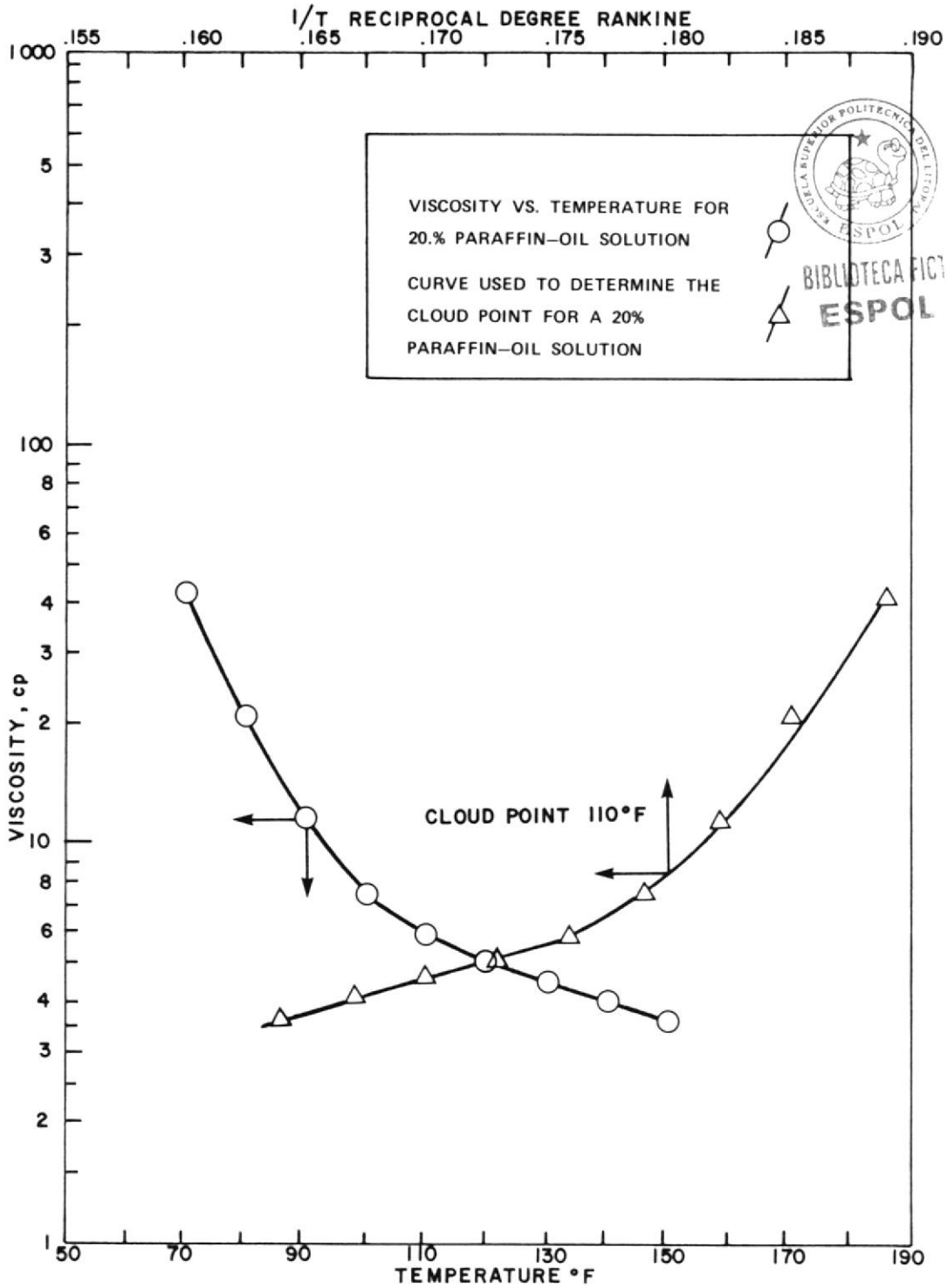


Figure 6. Viscosity vs. Temperature for 20% Paraffin-oil Solution

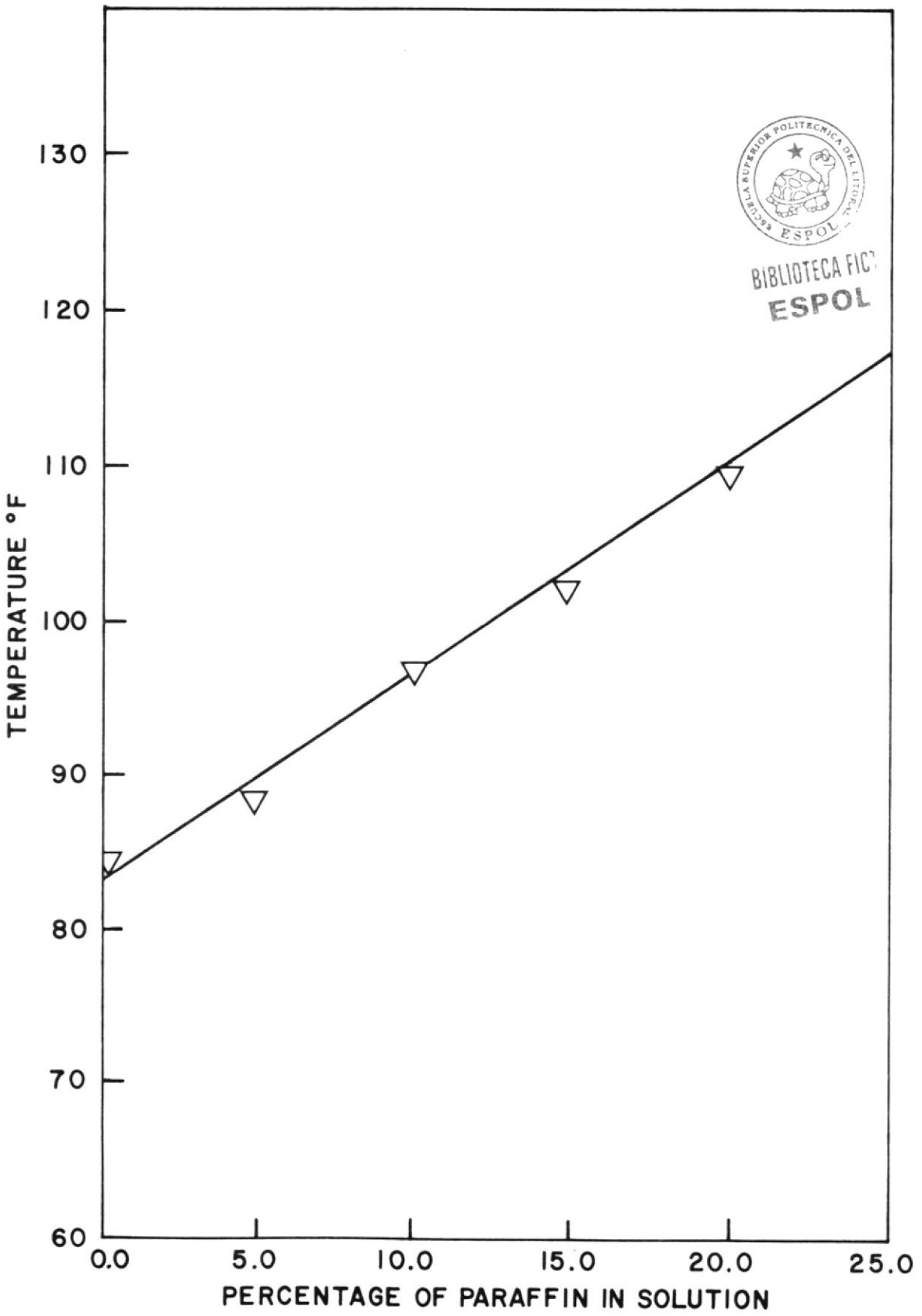


Figure 7. Change in Cloud Point Temperature with Paraffin Concentration

Solvent Stimulation

Five solvents were used in these experiments; gasoline, carbon tetrachloride, kerosene, naphtha, and toluene. Only toluene failed to restore some degree of permeability to the plugged core. Figures 8-12 show the results of these experiments. In every case, the solvent did not fully restore the permeability existing before the paraffin precipitation. Furthermore, the use of solvents will not prevent the accumulation of paraffin in the sandface or within the fractures.

Carbon tetrachloride was the solvent that allowed the highest increase in permeability (84%). This solvent is expensive and volatile, and as a consequence its use is not attractive for field applications.

In theory, solvents should remove all the paraffin, but this is very difficult to do within the fracture system and porous media. It is impractical because of the amount of solvent needed becomes very large. If a small slug of solvent is used, the solvent will be quickly saturated with paraffin and its dissolving action will be lost. It is impossible to do in a porous media because not all the formations are homogeneous and highly permeable. As was the case for the Berea cores used in these experiments, as a matter of fact most of the sandstones are extremely heterogeneous. As a consequence, the injected solvent will try to promptly override the oil through limited and narrow paths, and a good part of the sand will never be touched.

Table 6 summarizes the results obtained after solvent stimulation. Of all these solvents, the most attractive is kerosene, even though its effect is not as strong as carbon tetrachloride (46.39% permeability increase as compared to 84% of carbon tetrachloride). Kerosene is relatively inexpensive and much easier to handle than carbon tetrachloride.

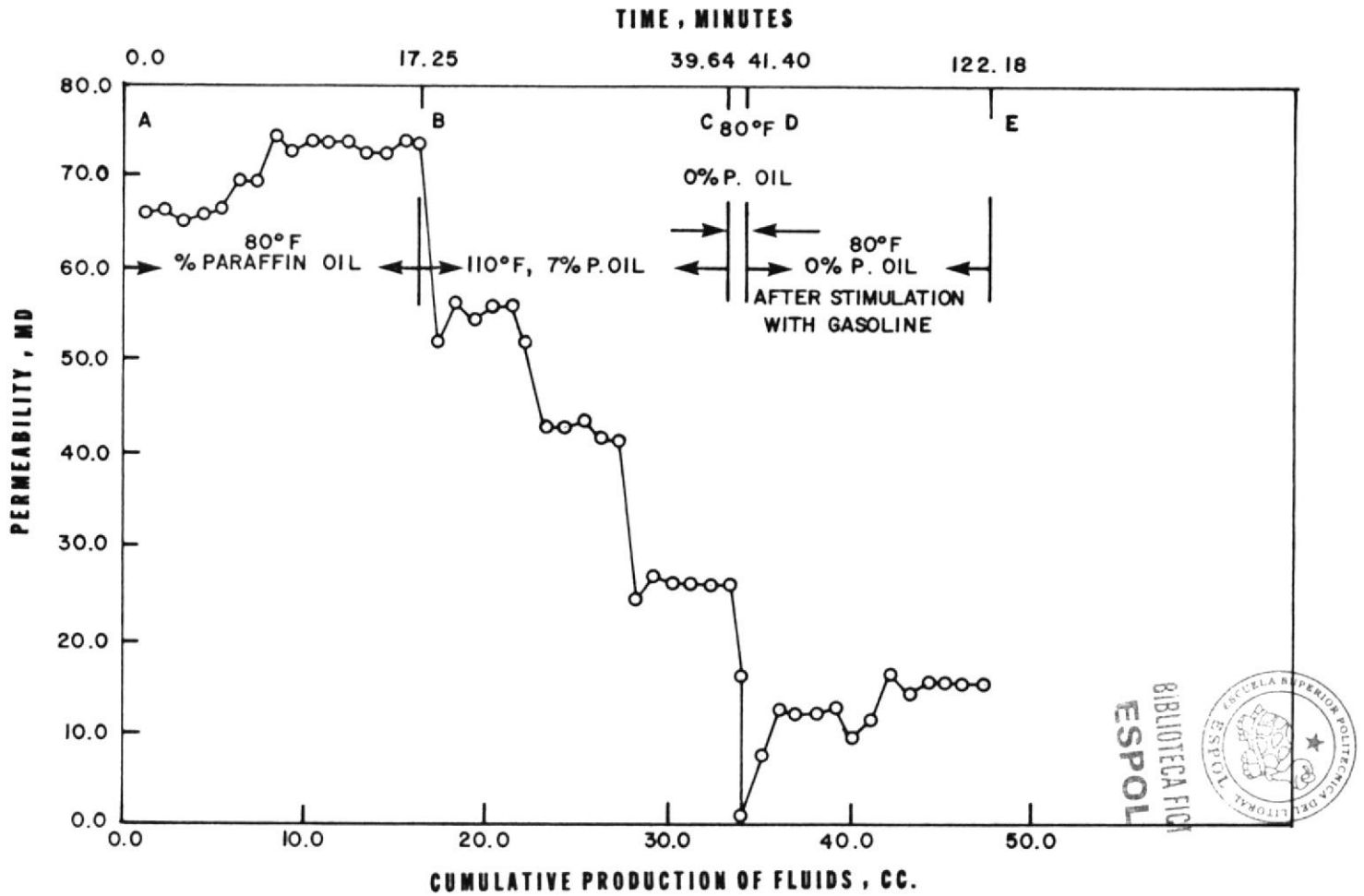


Figure 8. Change in Permeability with Time, Stimulation with Gasoline

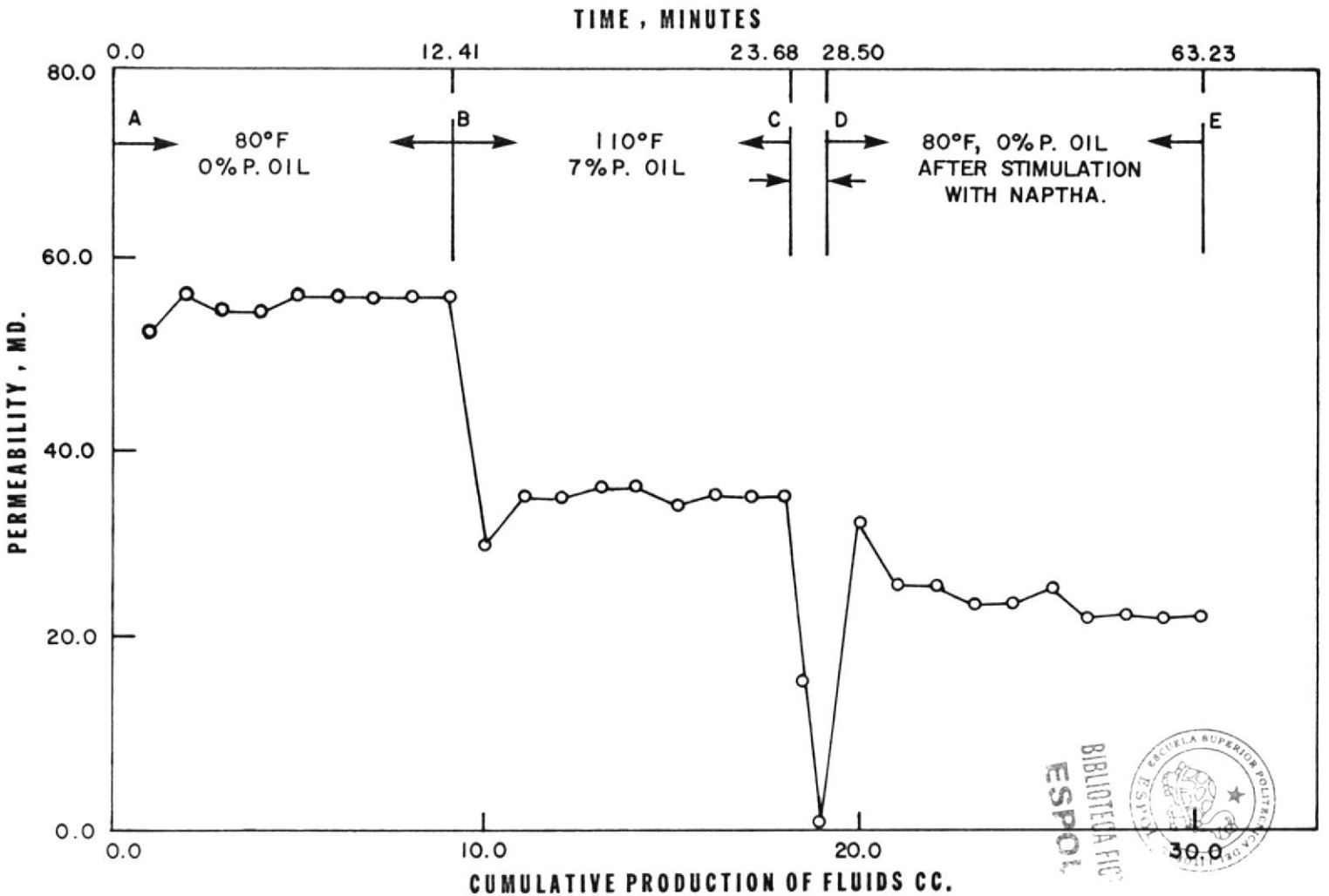


Figure 9. Change in Permeabili · with Time, Stimulation with Naphtha

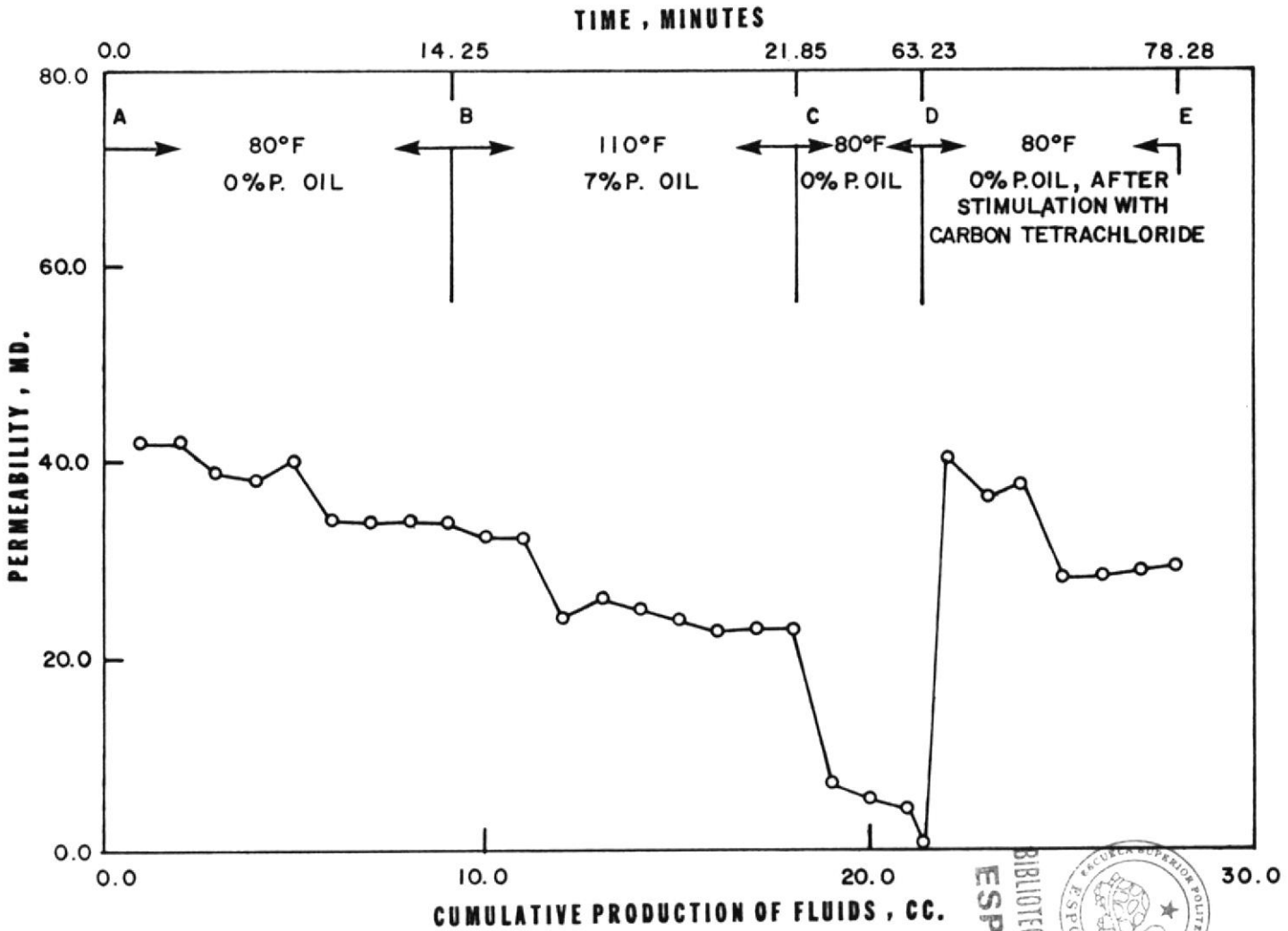


Figure 10. Change in Permeability with Time, Stimulation with Carbon Tetrachloride

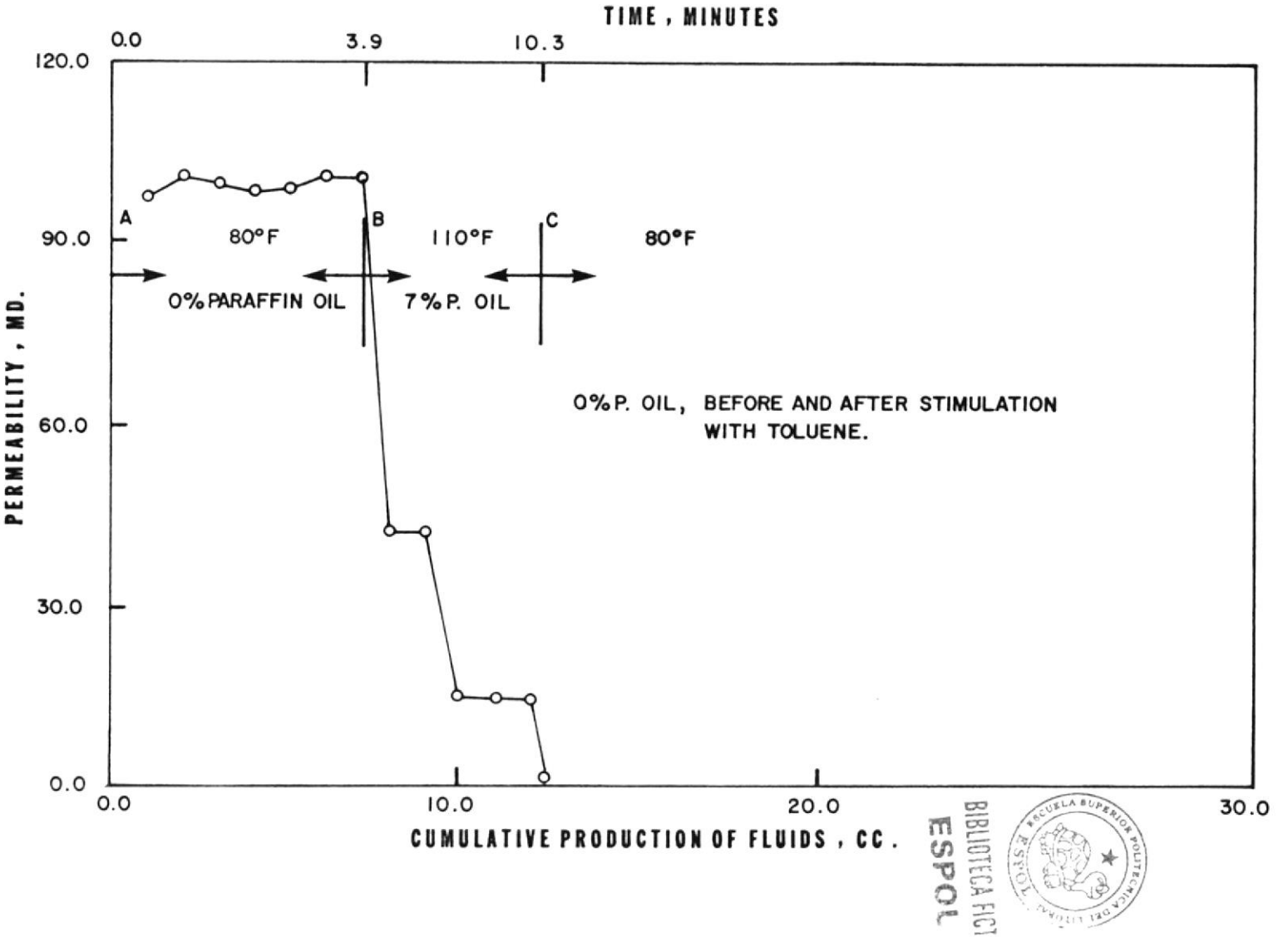


Figure 11. Change in Permeability with Time, Stimulation with Toluene

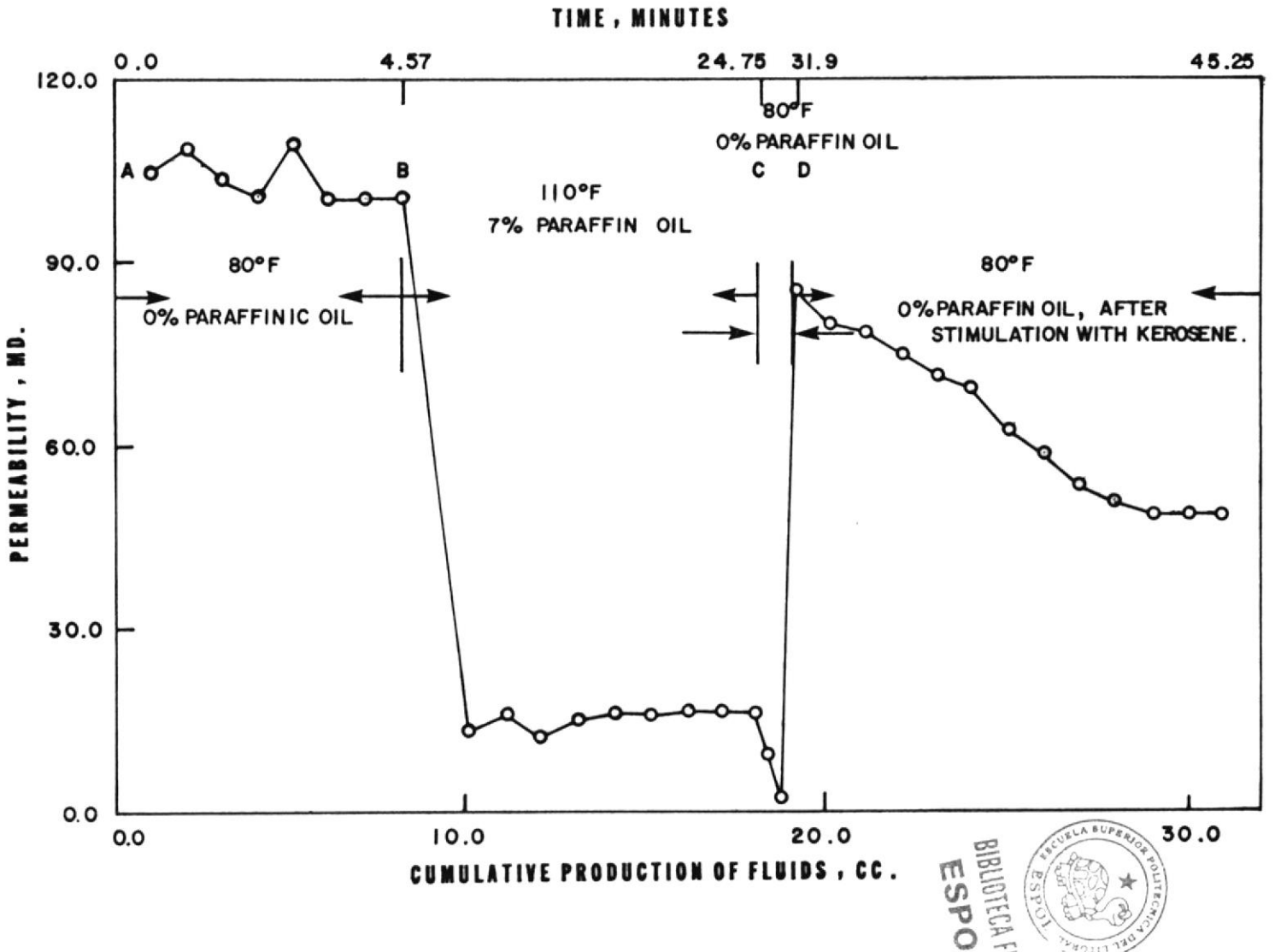


Figure 12. Change in Permeability with Time, Stimulation with Kerosene

TABLE 6

Results Obtained with Solvent Stimulation

SOLVENT	INITIAL PERM. OF THE CORE	% REDUCTION FROM PARAFFIN PLUGGING	% INCREASE FROM SOLVENT STIMULATION
Gasoline	74.1 md	*100%	**20.18%
Naphtha	56.36md	100%	41.31%
Carbon Tetrachloride	34.13md	100%	84. %
Toluene	105.54md	100%	0. %
Kerosene	104. md	100%	46.39%

*Percent Decrease = $\frac{\text{Permeability after Flowing with Paraffinic Oil}}{\text{Original Permeability}} \times 100$

**Percent Increase = $\frac{\text{Perm. of Plugged Core After Solvent Stimulation}}{\text{Original Permeability}} \times 100$

A solvent treatment would probably not affect the Clinton sandstone to any significant degree, so that only the fracture system will be affected. Hot solvent may be much more effective but the field operations would be much more dangerous.

The potential for a solvent stimulation does not begin to measure up to that of a thermal stimulation studied in the present investigation. The thermal stimulation has the potential for completely cleaning the fracture system as well as altering the adjacent formation. Improvements in terms of several orders of magnitude are possible. The solvent stimulation is measured in terms of a 20-60% improvement only.

It must be noticed that the paraffinic oil injected had only 7% of paraffin in solution, even smaller restoration of permeability should be expected, since if more paraffin is present, the solvent is saturated with solids faster.

Ultrasonic Energy Stimulation

A total of ten runs were made to investigate the effect of ultrasonic energy in the paraffin deposition problem. Of these ten runs, only seven are reported, the other three were not consistent. Several problems occurred with the ultrasonic probe used, and severe leaks in one of them caused meaningless results.

The seven runs reported showed rather consistent behavior. These experiments were carried out using highly paraffinic oils in Berea cores. The oil and paraffin used came from the Sandy Lake No. 3 well. From these experiments it can be said that ultrasonic energy does work as a stimulating agent to remove paraffin depositions in a reservoir rock.

Several slug sizes were tested as well as two concentrations of paraffin in oil (10% paraffin-oil solutions for runs 1-4). Tables 7-10

give the data, and Figures 13-16 are graphs pertaining to runs 1-4. Tables 11-13 and Figures 17-19 give the data for runs 5-7. For both cases (10% paraffin-oil, and 20% paraffin-oil), the percentage of permeability recovered was a function of the slug size, being larger for smaller size of slug. Figures 20 and 21 show this relationship for 10% paraffin-oil and 20% paraffin-oil respectively. The best improvement in permeability was for run 4 (51.22%, 10% pore volume (PV) slug, 10% paraffin-oil solution) and the poorest was for run 7 (7.41%, 75% PV slug, 20% paraffin-oil). Run 7 was also the one where the ultrasonic was used for longer periods of time (450 min.).

This run was the one case where stimulation occurred only during the time that the ultrasonic was working, but it must be considered that this was the largest slug used (75% PV of a 20% paraffin-oil solution). When the stimulation with the ultrasonic started, the first sample recovered (15cc in 240 minutes) had a viscosity of 97 cp. which is oil with a paraffin concentration of much more of 20%, all the other samples recovered had viscosities ranging from 17 cp to 7.4 cp, which corresponds to a range of 20% paraffin-oil to 5% paraffin-oil solutions (these numbers were estimated from the viscosity curves included Figures 3-6). When the paraffin oil is being injected at temperatures above its cloud point, all the paraffin is in solution. Once the temperature is dropped to a point below the cloud point, paraffin comes out of solution, plugging up the formation. Now, when stimulation with ultrasonic starts, part of this paraffin is redissolved but it could be possible that some paraffin, close enough to the production point (it must be remembered that this was observed only in run 7, where the largest slug, 75% PV with 20% paraffin-oil solution was injected) is

displaced without going back into solution and is produced as a high concentration paraffin-oil. This could be an explanation for the presence of that abnormally high paraffin concentration. It must be remembered that the rock acts like a filter. When the paraffinic oil is being displaced, only the oil advances and the paraffin precipitates, and concentrates in certain points of the face.

When preparing the solutions, it was necessary to have an oil with no paraffin in order to insure the exact concentration later when preparing the paraffin-oil solutions. To do this, it was necessary to cool the oil from the tanks to low temperatures (50°F - 45°F) and then filter the oil through filter paper (No. 5160, 250 MM). Pure oil was obtained but the filter paper was completely plugged up with paraffin. The same situation must occur in the sandstone. Table 13 summarizes the result obtained in these ultrasonic experiments. It can be seen that the improvement in permeability is independent on the time of ultrasonic stimulation. This could be because of the tool used. After 1 to 1 1/2 hours stimulation, the ultrasonic tool begins to show erratic behavior, that is why the stimulation periods were limited to 1/2 to 1 hours. The initial permeability of the core seems to be an important factor. For example, in run 3, a 50% PV slug was used and the improvement in permeability was 38.04%. The initial permeability was 152 md. In run 1 the size of the slug was 25% PV, and the increase in permeability was 39.7%, but the initial permeability was only 16 md.

Cavitation was defined by M. D. Rosenberg (24) as the formation and collapse of cavities in liquids either gas or vapor filled. In other words, it is a process characterized by the formation of bubbles in a liquid. These bubbles could be filled with the gas which was in the

liquid, and bubbles filled with liquid vapor.

Ultrasonic energy produces cavitation and cavitation is the process responsible for the increase in the kinetic energy of the fluid. When cavities are being formed the fluid undergoes a series of stress changes. During this process, the fluid is strongly agitated, and as a consequence, its ability to dissolve paraffin is very much increased. Figure 22 shows the increase in temperature in a fluid being activated by ultrasonic energy. As time increases, the temperature of the system also increases. This heat generation is another effect of ultrasonic energy, since sound energy transforms into heat with a definite ratio. Obviously, if temperature is increasing, all the paraffin will go in solution and above 130°F no paraffin exists in a solid state. Then the agitation of the system, and the increase in temperature are the principal factors affecting the removal of paraffins in the formation. Now, the generation of heat around the probe causes a problem with the tool itself, since the temperature increases with the operation time.

In a confined medium, the excessive heat around the probe causes defective operation of the instrument. Bilhartz (2) and associates observed similar problems in a field size tool. They developed some down hole tools and experimented with them. The results of their study showed that the heat generated during the operation was so great that the tool would burn itself up.

It is important to notice also that to operate properly the tool must be immersed in liquid, since in gas the ultrasonic energy is poorly transmitted. Experiments conducted with paraffin-oil solutions and formation waters showed that oil and water can be easily emulsified, this was observed by a change in color in the oil (from black to light brown)

TABLE 7

Stimulation with Ultrasonic Energy, Case 1

Core 1

D = 5.14 cm

L = 60.3 cm

A = 20.75 cm^2

μ_{oil} = 6.6 Cp

T = 80°F

Size of the slug of 10% Paraffin Oil = 24% PV

$\mu_{110°F}$ (10%) = 3.5

$\phi \simeq 20\%$

Time Sec.	Vol. cc	Pressure (At)	$\frac{\mu * L}{A.\Delta P}$	K_o (md)	K_w (md)	WOR (cc/cc)	Cum. Vol. cc	Fluid
1800.	25	2.04	9.40		19.78		25	Water
1800.	25	2.04	9.40		19.78		50	Water
1800.	25	2.04	9.40		19.78		75	Water
9000.	23	3.40	5.64	11.90	3.16	.2005	98	L. Oil
3600.	11.5	3.40	5.64	17.62	.198	.0002	109.5	L. Oil
3600	11.5	3.40	5.64	17.62	.198	.0002	121.0	L. Oil
3600	12.5	3.40	5.64	17.62	.00	.0	133.5	L. Oil
3600	11.5	3.40	5.64	17.62	.198	.022	145.0	L. Oil
3600	11.0	3.40	5.64	17.23	.00	0	156.0	L. Oil
3600	11.0	3.40	5.64	17.23	.00	0	167.0	L. Oil
7200	23.0	3.40	5.64	18.87	.00	0	190.0	L. Oil
7200	21.0	3.40	5.64	16.41	.00	0	211.0	L. Oil
7200	22.0	3.40	5.64	17.23	.00	0	233	L. Oil
7200	21.0	3.40	5.64	16.41	.00	0	254	L. Oil
7200	21.0	3.40	5.64	16.45	.00	0	275	L. Oil

TABLE 7 (continued)

T = 110°F

Time Sec.	Vol. cc	Pressure (At)	$\frac{\mu * L}{A.\Delta P}$	K_o (md)	K_w (md)	WOR (cc/cc)	Cu. Vol. cc	Fluid
3600	80	3.4	2.99	16.62	0.	0	295	10% P. Oil
3600	19	3.4	2.99	15.79	0.	0	314	
3600	15	3.4	2.99	12.46	0.	0	329	
1800	6	3.4	2.99	9.97	0.	0	333	

After 8 hrs. the temperature of the oven was 80°F, and reinjection of 0% paraffin oil started. After 1 1/2 hrs. no production was obtained as a consequence of the plugging.

Stimulation with ultrasonic energy started.

Production after Stimulation with Ultrasonic Energy								
7200	11	4.08	4.70	7.18	0.0		346	0% P. Oil
7200	11	9.08	4.70	7.18	0.0		357	
7200	8	9.08	4.70	5.22	0.0		365	
7200	8	4.08	4.70	5.22	0.0		373	
7200	10	4.08	4.70	6.53	0.0		383	
7200	9	9.08	4.70	5.88	0.0		392	
7200	10	9.08	4.70	6.53	0.0		402	
7200	9	4.08	4.70	5.88	0.0		411	
7200*	33	4.08	4.70	10.44	3.26	1.06	444	
7200	12	4.08	4.70	7.83	0.0		456	
7200	10	4.08	4.70	6.53	0.0		466	
7200	10	4.08	4.70	6.53	0.0		476	

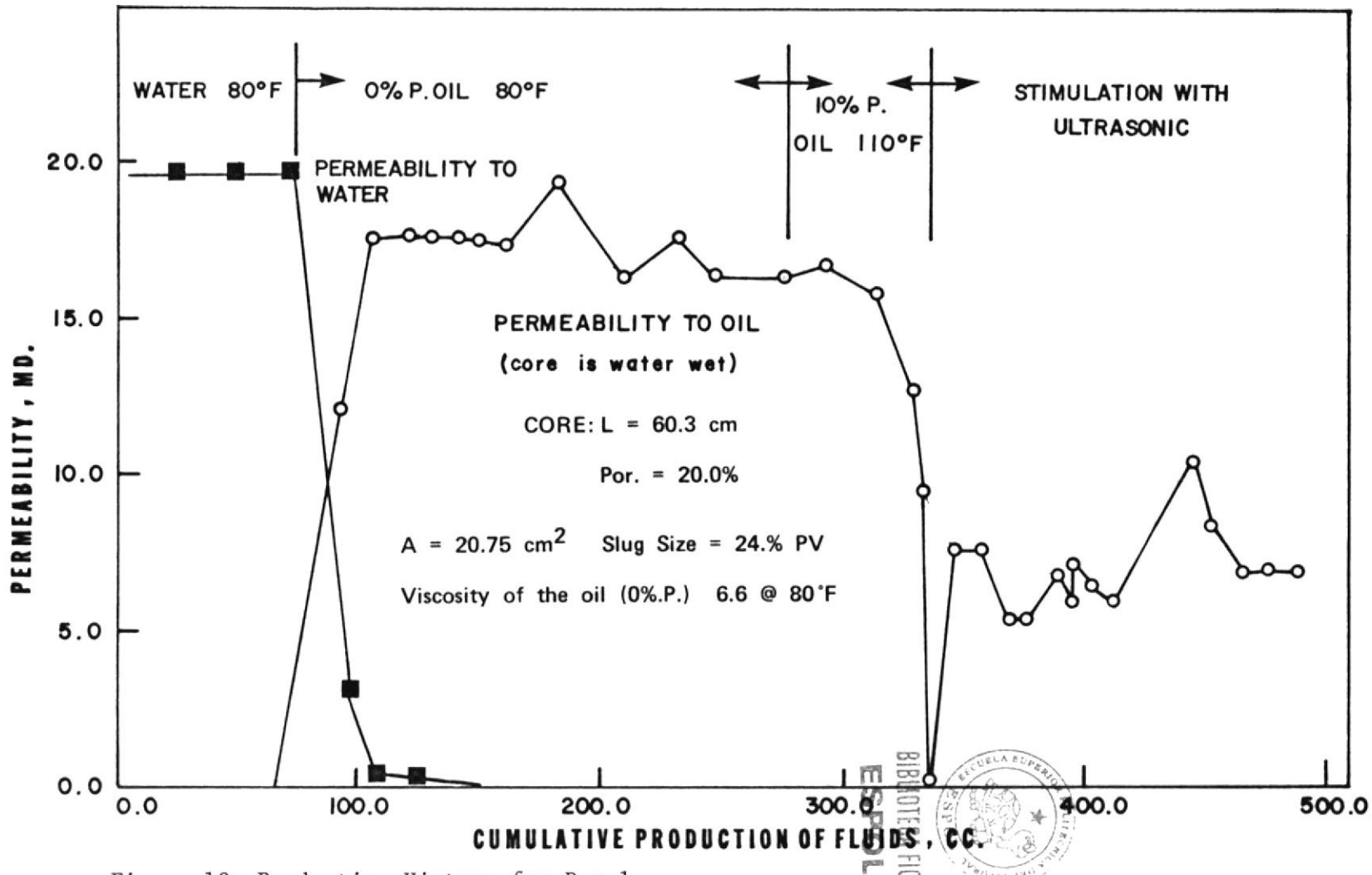


Figure 13. Production History for Run 1

TABLE 8

Stimulation with Ultrasonic Energy, Case 2

Core 2

D = 5.14 Size of the slug of 10% Paraffin Oil - 84.4% PV

L = 30 cm

A = 20.75

Time Sec.	Vol. cc	Pressure (At)	$\frac{\mu * L}{A.\Delta P}$	K_o (md)	K_w (md)	WOR (cc/cc)	Cum. Vol. cc	Fluid
180	12.5	.59	2.45		170.	-	12.5	Water
180	12.5	.59	2.45		170.	-	25.0	Water
180	12.5	.59	2.45		170.	-	37.5	Water
180	12.5	.59	2.45		170.	-	50.0	Water
180	12.5	.59	2.45		170.	-	62.5	Water
180	19.0	1.36	1.06		112.	-	81.5	0% P. Oil
180	6.0	1.36	1.06		35.4	-	87.5	"
180	5.0	1.36	1.06		29.53	-	92.5	"
1800	27.	1.36	1.06		15.90	-	119.5	"
1800	18.	1.27	1.14	-	11.35	-	137.5	"
1800	18.	1.27	1.14/6.84	26.6	3.48	1.57	155.5	"
3600	35.	1.27	1.14/6.84	61.75	1.58	.08	190.5	"
3600	35.	1.27	1.14/6.84	61.75	1.58	.08	225.5	"
3600	38.	1.27	6.84	72.2	-	-	263.5	"
3600	38.	1.27	6.84	72.2	-	-	301.5	"
3600	38.	1.27	6.84	72.2	-	-	339.5	"

TABLE 8 (continued)

T = 110°F

Time Sec.	Vol. cc	Pressure (At)	μ *L A.ΔP	K_o (md)	K_w (md)	WOR (cc/cc)	Cum. Vol. cc	Fluid
3600	38.5	2.04	2.48	26.52	-	-	378.0	10% P. Oil
3600	23.5	2.04	2.48	16.19	-	-	401.5	"
3600	22.8	2.04	2.48	15.71	-	-	424.3	"
3600	22.8	1.87	2.27	14.38	-	-	447.1	"
3600	13.0	1.87	2.27	8.20	-	-	460.1	"
3600	10.0	1.87	2.27	6.31	-	-	470.1	"
3600	8.0	1.87	2.27	5.04	-	-	478.1	"
3600	5.0	1.87	2.27	3.15	-	-	483.1	"
			Stimulation with Ultrasonic Energy					
7200	5	3.74	2.55	1.77	-	-	488.1	0% P. Oil
7200	11	3.74	2.55	3.90	-	-	499.1	"
7200	15	3.74	2.55	5.31	-	-	514.1	"
7200	17	3.74	2.55	6.02	-	-	531.1	"
7200	20	3.74	2.55	7.08	-	-	551.1	"
7200	23	3.74	2.55	8.14	-	-	574.1	"
7200	25	3.74	2.55	8.85	-	-	599.1	"
7200	27	3.74	2.55	9.56	-	-	626.1	"
7200	28	3.74	2.55	9.91	-	-	654.1	"
7200	45	3.74	2.55	10.62	.8054	.500	699.1	"
7200	38	3.74	2.55	10.62	.4293	.2667	727.1	"
7200	35	3.74	2.55	12.39	-	-	762.	"
7200	35	3.74	2.55	12.39	-	-	797.	"
7200	35	3.74	2.55	12.39	-	-	832.	"

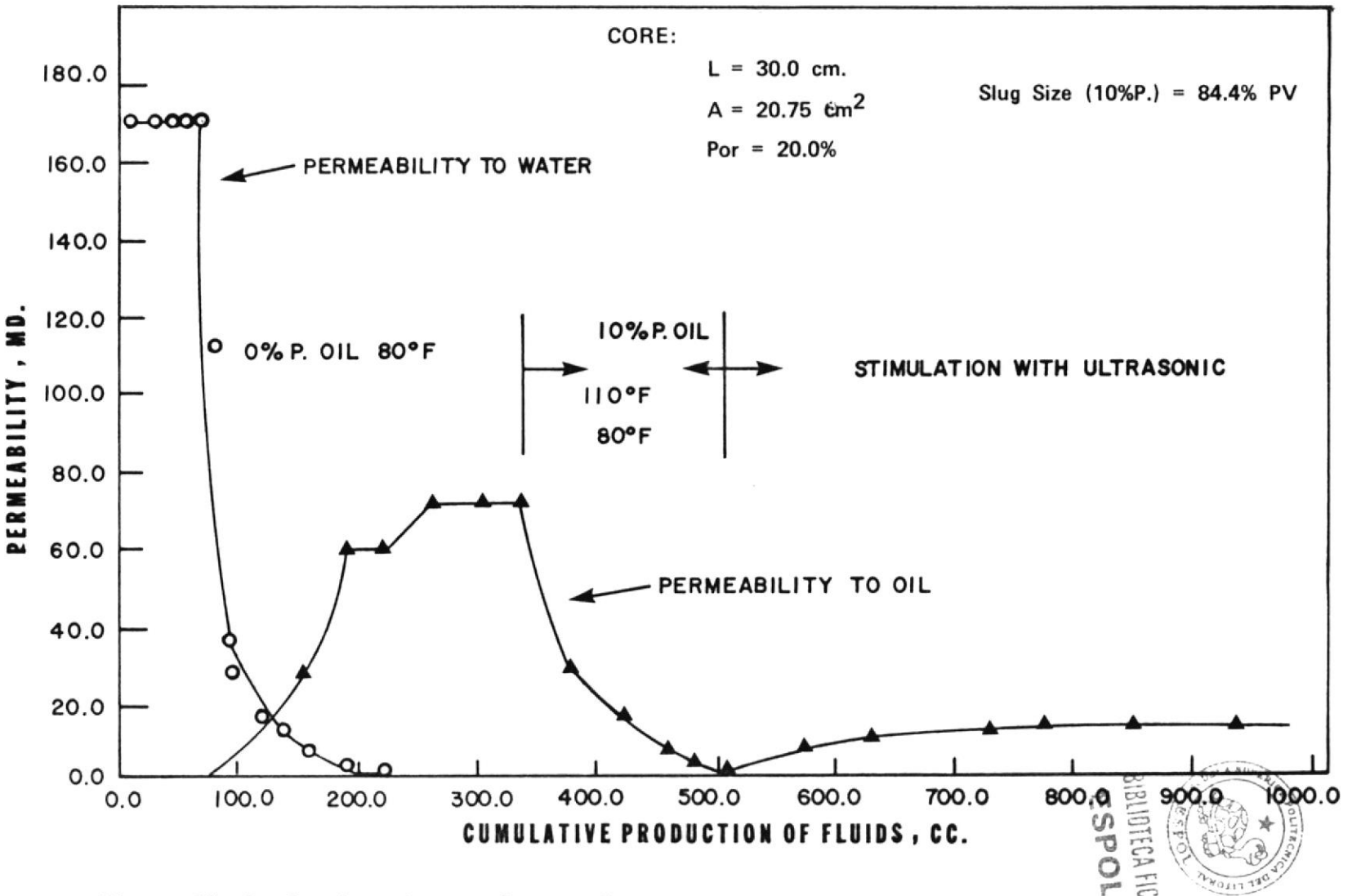


Figure 14. Production History for Run 2

TABLE 9

Stimulation with Ultrasonic Energy, Case 3

Core 3

L = 60.3 cm Slug size = 50% P.V

A = 20.75 cm^2 μ oil = 5.83 cp

Time (Sec.)	Vol. (cc)	Cum. V (cc)	Pressure (At)	$\frac{\mu * L}{A.\Delta P}$	K_o (md)	K_w (md)	WOR cc/cc	Fluid
360.	45	45	0.95	3.06	-	382.5	-	Water
360.	45	90	0.95	3.06	-	382.5	-	"
360.	45	135	0.95	3.06	-	382.5	-	"
360.	45	180	0.95	3.06	-	382.5	-	"
360.	40	220	1.36	3.06	-	237.4	-	Oil 0% P.
360.	22	242	1.36	2.14	-	130.8	-	"
1080.	38	280	1.36	2.14	-	75.3	-	"
1080.	26	306	1.36	2.14	-	51.5	-	"
2160.	40	346	1.36	2.14	-	39.6	-	"
2160.	30	376	1.36	2.14	-	29.7	-	"
2160.	32	408	2.04	8.30	46.14	19.81	-	"
2880.	43	451	2.04	8.30	123.92	-	-	"
2880.	41	492	2.04	8.30	118.16	-	-	"
2880	47	539	2.04	8.30	135.45	-	-	"
2880.	49	588	2.04	8.30	141.22	-	-	"
2880.	49	637	2.04	8.30	141.22	-	-	"
2880	51	688	2.04	8.30	146.98	-	-	"
2880	53	741	2.04	8.30	152.74	-	-	"
2880	52	793	2.04	8.30	149.86	-	-	"
2880	53	846	2.04	8.30	152.74	-	-	"
2880	53	899	2.04	8.30	152.74	-	-	"
2880	53	952	2.04	8.30	152.74	-	-	"
T = 110°F								
2880	60	1012	2.04	8.30	108.87	-	-	Oil 10% P.
1880	50	1062	2.04	8.30	132.60	-	-	"
720	15	1077	2.04	8.30	103.87	-	-	"
1440	3.5	1080.5	1.90	8.30	21.67	-	-	"
5400	22	1102.5	3.4	4.98	20.30	-	-	"
Production after Stimulation with Ultrasonic Energy								
7200	46	1148.5	3.4	4.98	31.82	-	-	"
7200	54	1262.5	3.4	4.98	33.20	-	-	"
3600	32.5	1235.0	3.4	4.98	42.88	-	-	"
3600	36.5	1271.5	3.4	4.98	50.49	-	-	"
3600	35.0	1306.5	3.4	4.98	48.42	-	-	"
3600	36.5	1343.0	3.4	4.98	50.49	-	-	"
3600	37.5	1380.5	3.4	4.98	51.88	-	-	"
3600	39.0	1419.5	3.4	4.98	53.95	-	-	"
1800	21.0	1440.5	3.4	4.98	58.10	-	-	"
1800	21.0	1461.5	3.4	4.98	58.10	-	-	"
3300	38.5	1500.0	3.4	4.98	58.0	-	-	"

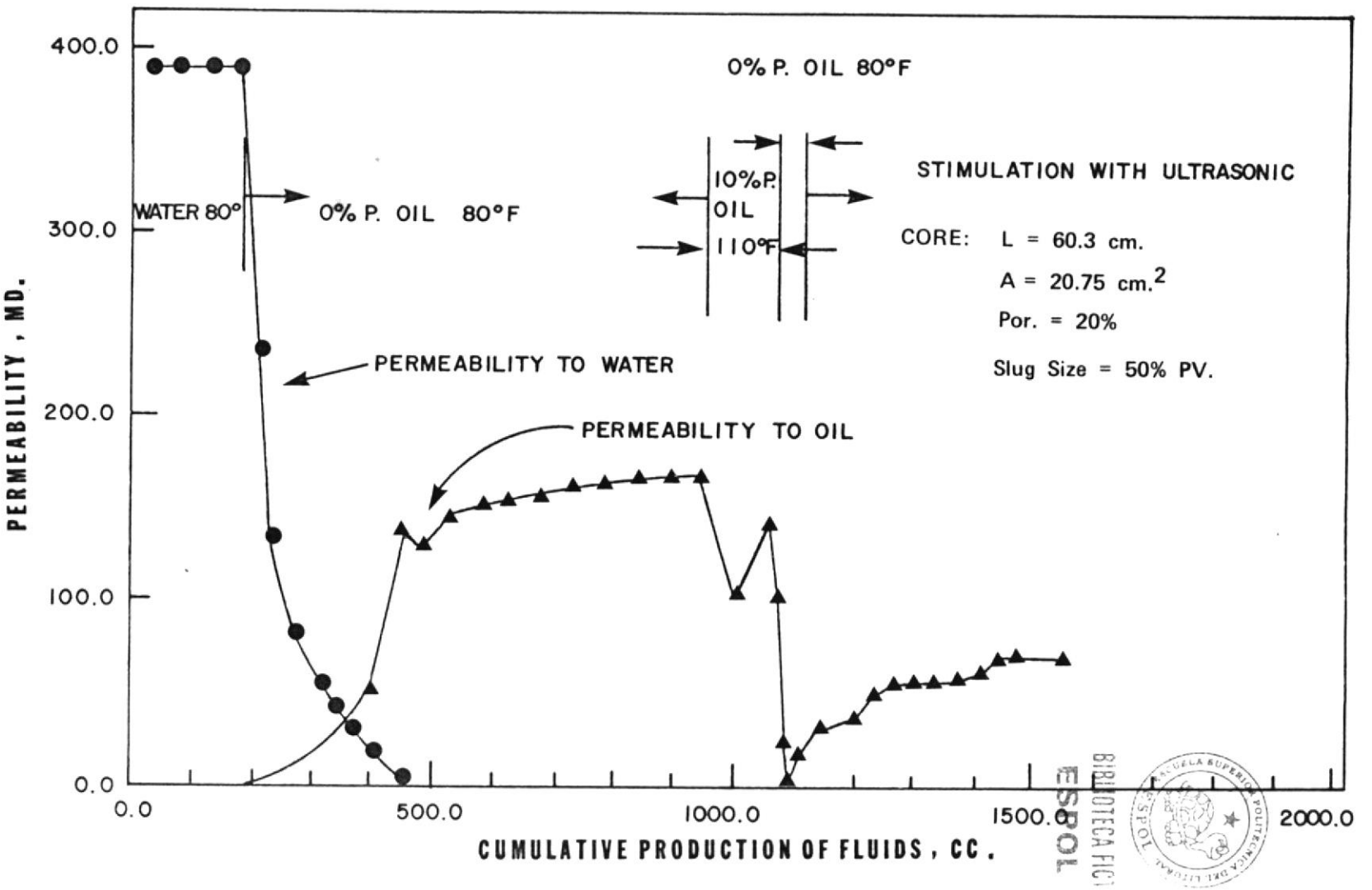


Figure 15. Production History for Run 3

TABLE 10

Stimulation with Ultrasonic Energy, Case 4

Core 4

L = 30 cm. ϕ = 20% Slug size = 14% PV

A = 20.75 μ oil = 5.83 cp (0% P.)

Time (Sec.)	Cum. Time	Vol. (cc)	C.Vol. (cc)	Pressure (At)	$\frac{\mu * L}{A.\Delta P}$	K_o (md)	K_w (md)	WOR (cc/cc)	Fluid
130	2.17	15	15	.95	1.52	-	175.38	-	Water
130	4.34	15	30	.95	1.52	-	175.38	-	"
130	6.51	15	45	.95	1.52	-	175.38	-	"
130	8.68	15	60	.95	1.52	-	175.38	-	"
130	10.85	11	71	1.36	1.52	-	128.62	-	0% P. Oil
130	13.02	10	81	1.36	1.52	-	116.42	-	"
390	19.52	20	91	1.36	1.52	-	77.95	-	"
195	22.77	9	99	1.36	1.52	-	70.15	-	"
650	33.60	24	123	2.04	1.01	-	37.29	-	"
1800	63.60	21	144	2.04	5.89	52.34	.42	-	"
1800	93.60	26	170	2.04	5.89	85.08	-	-	"
1800	123.60	27	197	2.04	5.89	88.35	-	-	"
3600	183.60	32	229	1.36	6.20	55.11	-	-	"
3600	243.60	41	770	1.36	6.20	70.61	-	-	"
3600	303.60	45	315	1.36	6.20	77.50	-	-	"
3600	363.60	47	362	1.36	6.20	80.84	-	-	"
3600	423.60	51	413	1.36	6.20	87.83	-	-	"
3600	483.60	51	464	1.36	6.20	87.83	-	-	"
3600	543.60	51	615	1.36	6.20	87.83	-	-	"
720	555.60	11	526	1.36	3.72	56.85	-	-	"
T = 110°F									
720	567.60	2	534	1.36	3.72	41.33	-	-	"
720	579.60	6	540	1.36	3.72	31.00	-	-	"
Production after Stimulation with Ultrasonic Energy									
720	591.60	2	542	1.36	6.20	17.22	-	-	10% P. Oil
1800	621.60	10	552	1.36	6.20	34.44	-	-	"
1800	651.60	13	565	1.36	6.20	44.78	-	-	"
1800	681.60	13	578	1.36	6.20	44.78	-	-	"
1800	711.60	13	591	1.36	6.20	44.78	-	-	"
1800	741.60	13	604	1.36	6.20	44.78	-	-	"
1800	756.60	6.5	10.6	1.36	6.20	44.78	-	-	"

% Rec. = 51%

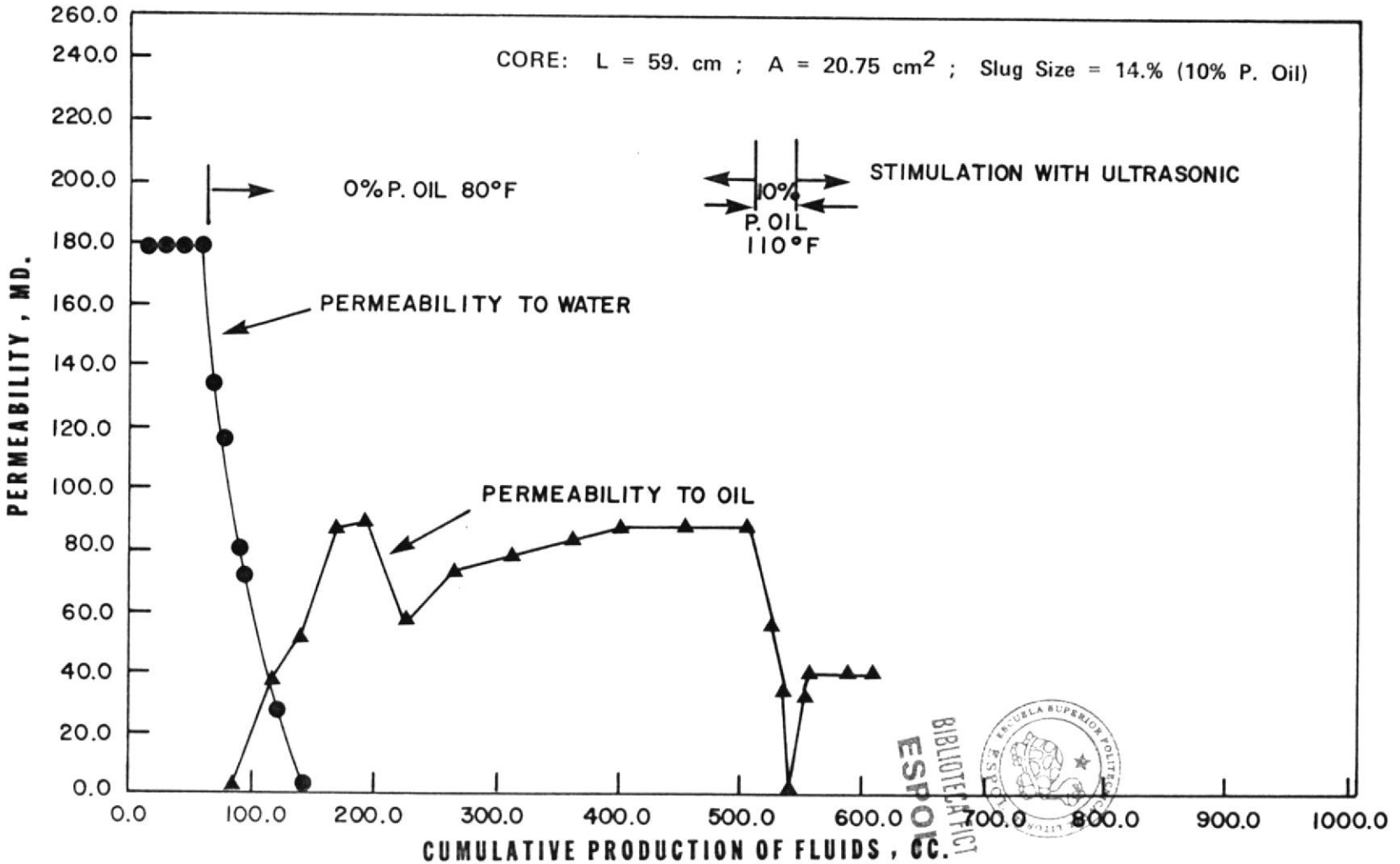


Figure 16. Production History for Run 4

TABLE 11

Stimulation with Ultrasonic Energy, Case 5

Core No. 5

L = 27.9 ϕ = 20% Slug size = 25% PV (28.28cc)

A = 20.27 cm^2 Pore Vol. = 113.11 cm^3

Time (Sec.)	Vol. (cc)	Pressure (At)	μ *L / A	K_o (md)	K_w (md)	Cum.Vol. (Min.)	Cum.Time (Min.)	Fluid
360	40	.41	1.38	-	373.01	40.	6	Water
360	30	.24	"	-	477.9	70.	12	"
360	40	.37	"	-	413.14	110.	18	"
360	44	.44	"	-	382.34	154.	24	"
360	41	.41	"	-	382.34	195.	30	"
360	39	.41	"	-	363.69	234.	36	"
360	39	.41	"	-	363.69	273.	42	"
360	41	.41	"	-	382.34	314.	48	"
360	39	.41	"	-	363.69	353.	54	"
360	35	1.01	"	-	132.49	388.	60	0% P. Oil
360	12	.99	"	-	46.34	400.	66	"
360	10	.99	"	-	38.62	410.	72	"
720	16.5	.97	"	-	32.52	426.5	84	"
1800	30	.97	"	-	23.65	456.5	114	"
1800	33	.97	7.84	101.11	8.67	489.5	144	"
2700	41	.97	7.84	125.62	-	530.5	189	"
2700	38	.97	"	116.46	<.01	568.5	234	"
2700	45	.97	"	137.83	<.01	613.5	279	"
2700	44	.97	"	134.81	<.01	657.5	324	"
2700	42	.97	"	128.69	-	699.5	369	"
2700	43	.97	"	131.71	-	742.5	414	"
2700	43	.97	"	131.71	-	785.5	459	"
2700	41	.97	"	125.58	-	826.5	504	"
2700	38	.86	"	131.32	-	864.5	549	"
2700	43	.97	"	131.71	-	907.5	594	"
2700	38	.97	"	116.39	-	945.5	639	"
2700	45	.95	7.84	137.52	-	990.5	684	"
360	7	.95	"	160.47	-	997.5	690	"
360	7	.95	"	160.47	-	1004.5	696	"
360	7	.95	"	160.47	-	1011.5	702	"
Temp. = 120°F								
720	6.5	.99	"	71.75	-	1018.0	714	20% P. Oil
720	6.0	.99	"	65.99	-	1024.0	726	"
720	6.0	.99	"	65.99	-	1030.0	738	"
720	6.5	.99	7.84	71.49	-	1036.5	750	"

TABLE 11 (continued)

Production after Stimulation with Ultrasonic Energy

Time (Sec.)	Vol. (cc)	Pressure (At)	$\frac{\mu * L}{A}$	K_o	K_w	Cum.Vol. (cc)	Cum.Time (Min.)	Fluid
360	3.5	.97	7.84	78.58	-	1040.0	756	0% P. Oil
1800	3.5	1.03	"	14.80	-	1043.5	786	"
1800	4.0	1.03	"	16.91	-	1047.5	816	"
3600	9.0	1.22	"	16.07	-	1056.5	876	"
3600	9.0	1.22	"	16.07	-	1065.5	936	"
3600	9.3	1.22	"	16.60	-	1074.8	996	"
3600	9.3	1.22	"	16.60	-	1084.1	1056	"
3600	9.0	1.22	"	16.07	-	1093.1	2112	"
3600	9.5	1.02	"	20.28	-	1102.6	2172	"
2700	53.	2.79	"	54.12	-	1154.6	2217	"
2700	66.	2.79	"	68.69	-	1220.6	2262	"
720	18.	2.79	"	70.25	-	1238.6	2278	"
720	18.	2.79	"	70.25	-	1256.6	2786	"
720	18.	2.79	"	70.25	-	1274.6	2298	"

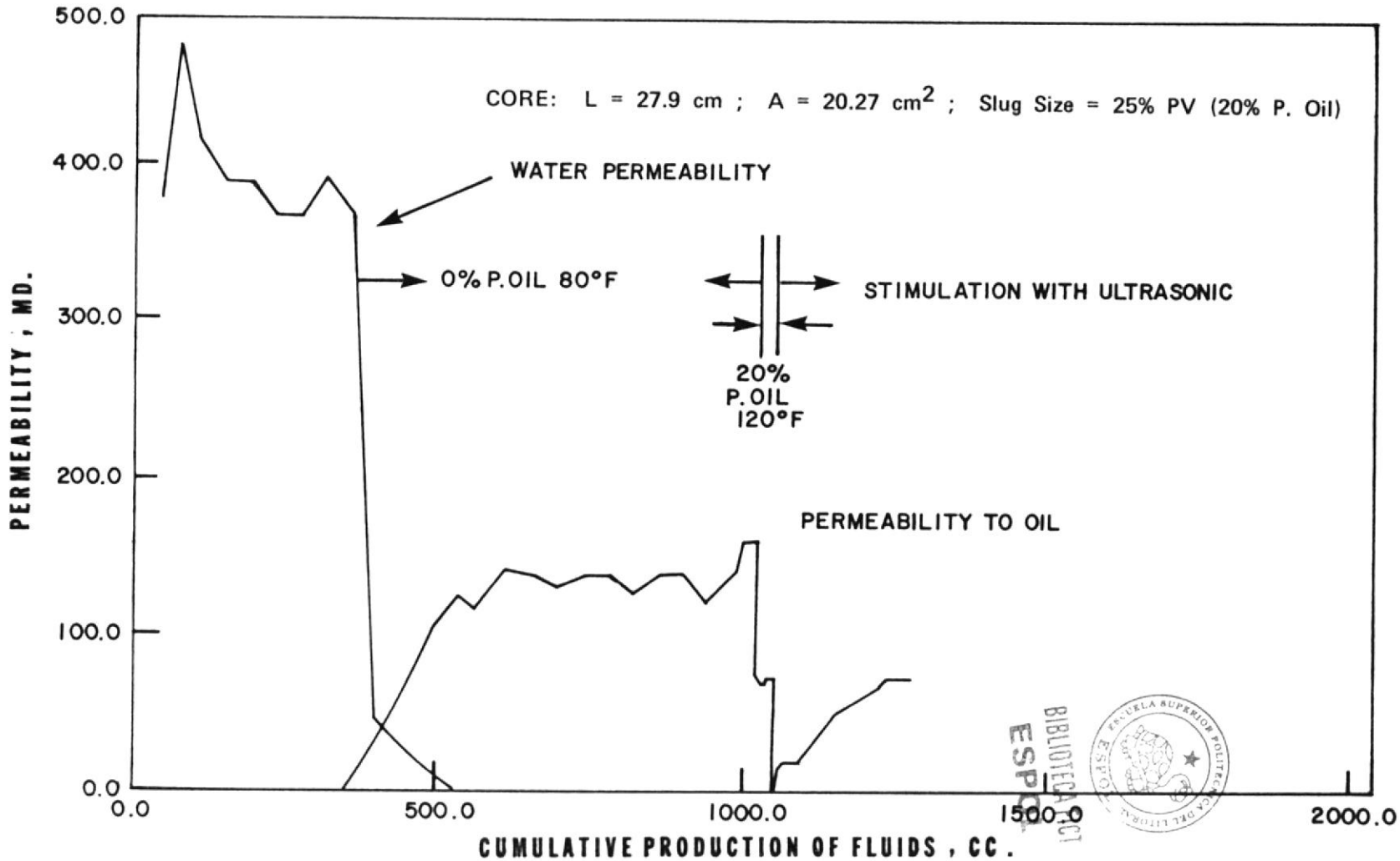


Figure 17. Production History for Run 5

TABLE 12

Stimulation with Ultrasonic Energy, Case 6

Core No. 6

Core L = 50 cm Slug size (20% P. Oil) = 50% PV

A = 20.75 $\mu_{20\%\ P.O.\ @\ 120°F}$

ϕ = 20% $\mu_{0\%\ P.O.\ @\ 80°F} = 5.83$

Time (Sec.)	Vol. (cc)	Pressure (At)	$\frac{\mu * L}{A}$	K_o (md)	K_w (md)	WOR (cc/cc)	Cum.(Min.) Time	Cum. Vol. cc	Fluid
360	25	1.0	2.84	-	197.46	-	6	25	Water
360	26	1.0	"	-	205.11	-	12	51	"
360	25	1.0	"	-	197.46	-	18	76	"
360	25	1.0	"	-	197.46	-	24	101	"
360	25	1.0	"	-	197.46	-	30	126	"
720	25	1.0	"	-	106.50	-	36	153	Oil 0%
1080	23	1.0	"	-	60.48	-	48	176	"
2160	30	1.0	"	-	39.44	-	66	206	"
2160	21	1.0	"	-	27.61	-	102	227	"
2160	15	1.0	"	-	19.72	-	138	242	"
2160	11	1.0	"	-	14.46	-	174	253	"
2160	8	1.0	"	-	10.52	-	210	261	"
2160	4.5	1.0	"	-	5.92	-	246	265.5	"
2160	4.0	1.0	"	-	5.26	-	282	269.5	"
2160	3.5	1.0	"	-	4.60	-	318	269.5	"
2160	3.5	1.0	"	-	4.60	-	354	276.5	"
7200		2.0	1.42/8.28	2.30	3.75	9.5	444	297.5	"
7200		2.0	2.84/16.58	21.30	0.30	12.33	564	317.5	"
7200		2.0	16.58	27.63	0.20	0.04	684	342.5	"
7200		2.0	16.58	29.94	0.39	-	804	370.5	"
7200		2.0	16.58	26.48	0.20	-	924	394.5	"
7200	22	2.0	16.58	25.33	-	-	1064	416.5	"
7200	20	2.0	"	23.03	-	-	1164	436.5	"
7200	18	2.0	"	20.73	-	-	1284	454.5	"
7200	10	2.0	"	11.51	-	-	1404	464.5	"
7200	55	3.74	"	33.86	-	-	1524	519.5	"
7200	89	3.74	"	54.80	-	-	1644	608.5	"
7200	89	3.74	"	54.80	-	-	1764	697.5	"
7200	12	3.74	"	73.89	-	-	1776	709.5	"
720	11	3.74	"	67.73	-	-	1788	720.5	"
720	11	3.74	"	67.73	-	-	1800	731.5	"
720	11	3.74	"	67.73	-	-	1812	742.5	"

TABLE 12 (continued)

Time (sec.)	Vol. (cc)	Pressure (At)	$\frac{\mu * L}{A}$	K_o (md)	K_w (md)	WOR (cc/cc)	Cum.(Min.) Time	Cum. Vol. cc	Fluid
T = 120°F									
3600	32	13.05	2.72	42.65	< .01	-	774.5	1844.	20% P.Oil
3600	37	13.05	3.40	39.45	< .01	-	811.5	1881.	"
3600	17	"	3.40	18.13	< .01	-	828.5	1898.	"
3600	15	"	4.08	13.33	< .01	-	843.5	1913.	"
3600	13	"	4.42	10.66	< .01	-	806.5	1926.	"
1860	8	"	4.59	12.23	< .01	-	864.5	1934.	"
Production after Stimulation with Ultrasonic Energy									
5400	1.5	16.58	2.38	1.94	< .01	-	866.0	1935.5	0% P.Oil
5400	13	"	4.08	9.78	"		879.0	1948.5	"
7200	20	"	4.08	11.29	"	-	899.0	1968.5	"
7200	20	"	4.08	11.29	"	-	919.0	1968.5	"
7200	21	"	4.08	11.85	"	-	940.0	2000.5	"
7200	22	"	4.08	12.42	"	-	962.0	2031.5	"
7200	23	"	4.08	12.98	"	-	985.0	2054.5	"
7200	24	"	4.08	13.55	"	-	1009.0	2078.5	"
7200	30	"	3.74	18.47	"	-	1039.0	2108.5	"
7200	29	"	3.74	15.80	"	-	1068.0	2137.5	"
7200	18	"	4.08	15.80	"	-	1096.0	2165.5	"
7200	27	"	4.08	15.24	"	-	1123.0	2192.5	"
7200	25	"	4.08	14.11	"	-	1148.0	2217.5	"
7200	25	"	4.08	14.11	"	-	1173.0	2242.5	"
3600	16	"	4.08	18.06	"	-	1189.0	2248.5	"
5400	22	"	4.08	16.54	"	-	1211.0	2280.5	"
5400	17	"	4.08	12.79	"	-	1228.0	2297.5	"
5400	10	"	4.08	7.53	"	-	1238.0	2307.5	"
5400	9	"	4.08	6.77	"	-	1247.0	2316.5	"
5400	8	"	4.08	6.02	"	-	1255.0	2324.5	"
5400	7	"	4.08	5.27	"	-	1262.0	2331.5	"
3600	6	"	4.08	6.77	"	-	1268.0	2337.5	"
3600	10	"	4.08	11.29	"	-	1278.0	2347.5	"
3600	10	"	4.08	11.28	"	-	1288.0	2357.5	"
3600	8	"	4.08	9.03	"	-	1296.0	2365.5	"
3600	8	"	4.08	9.03	"	-	1304.0	2373.5	"
3600	8	"	4.08	9.03	"	-	1312.0	2381.5	"
3600	8	"	4.08	9.03	"	-	1320.0	2389.5	"

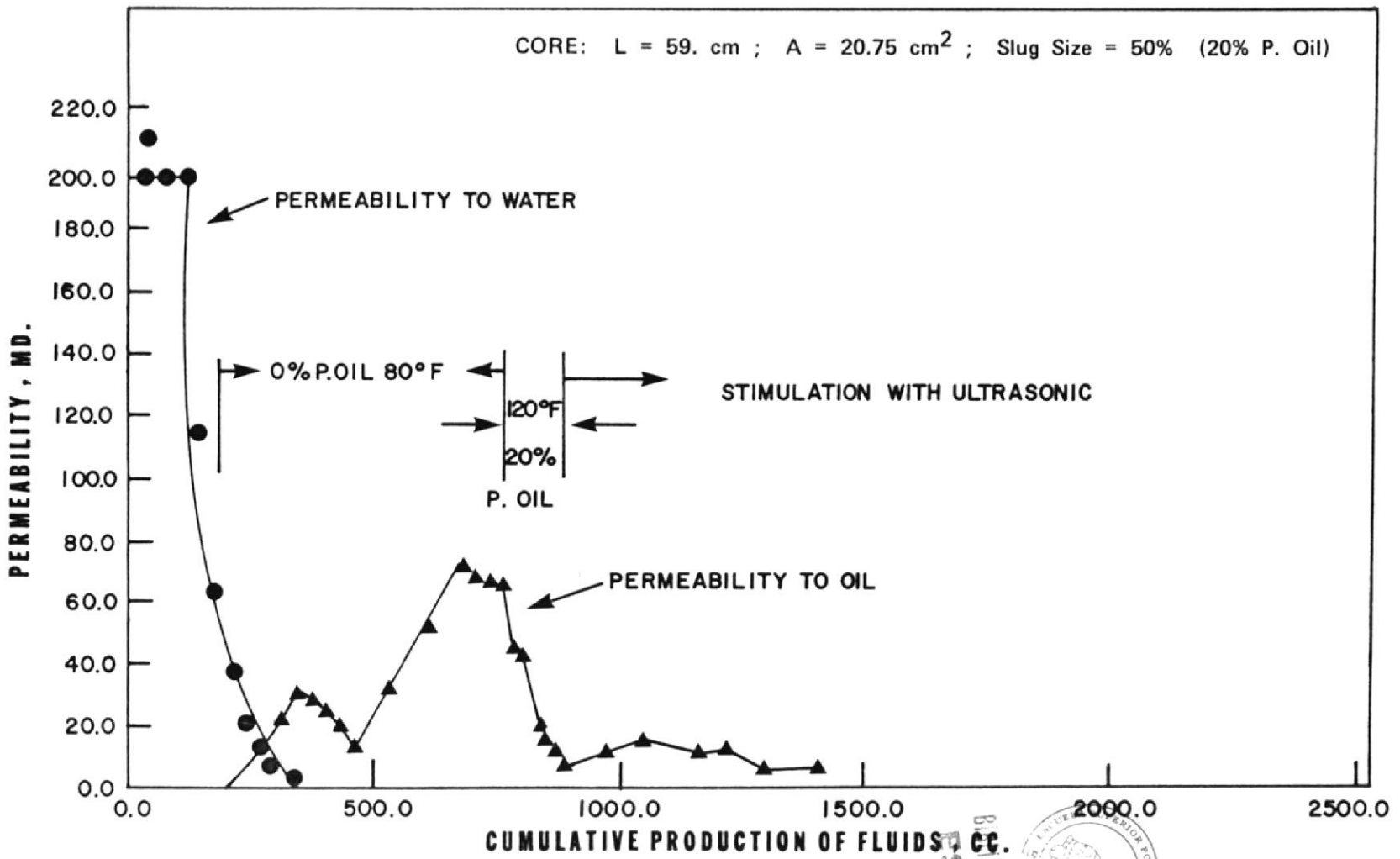


Figure 18. Production History for Run 6

TABLE 13

Stimulation with Ultrasonic Energy, Case 7

Core No. 7

L = 29.6 cm Slug size - 75% PV (20% P. Oil)

A = 20.75 cm^2

Time (sec.)	Vol. (cc)	Press. (At)	$\frac{\mu * L}{A}$	K_o (md)	K_w (md)	Cum.Min. Time	Cum. Vol.cc	Fluid
360	34	.82	1.43		164.7	6	34.0	Water
360	37.5	.82	1.43		181.6	12	71.5	"
360	37.5	.87	1.43		181.6	18	109.0	"
360	37.5	.82	1.43		181.6	24	146.5	"
720	30.0	.73	1.43		81.6	36	176.5	0% P.Oil
1800	22.0	1.12	1.43		15.61	66	198.5	"
3600	26.0	1.63	1.43		6.34	126	224.5	"
3600	16.0	1.63	1.43		3.90	186	240.5	"
3600	24.0	2.04	1.43		4.67	246	264.5	"
1800	15.0	2.04	1.43/8.32	26.06	.96	276	279.5	"
1800	24.0	3.74	1.43/8.32	26.58	.96	306	303.5	"
1800	18.0	"	8.32	22.24	-	336	321.5	"
1800	30.0	"	"	37.08	-	366	351.5	"
900	38.0	"	"	93.92	-	381	389.5	"
900	38.0	"	"	93.92	-	396	427.5	"
900	38.0	"	"	93.92	-	411	475.5	"
600	25.0	"	"	92.69	-	421	490.5	"
600	25.0	"	"	92.69	-	431	515.5	"
600	25.0	"	"	92.69	-	441	540.5	"
600	25.0	"	"	92.69	-	451	565.5	"
600	25.0	"	"	92.69	-	461	490.5	"
T = 120°F								
1800	17.0	3.40	8.46	23.50	-	481	607.5	20% P.Oil
1800	17.0	3.40	8.46	23.50	-	521	624.5	"
1800	13.0	"	"	17.97	-	551	637.5	"
3600	25.0	"	"	17.28	-	611	662.5	"
2400	20.0	"	"	20.74	-	651	682.5	"
Production after Stimulation with Ultrasonic Energy								
3600	5.5	"	8.32	3.74	-	711	688.0	0% P.Oil
3600	4.0	"	"	2.72	-	771	692.0	"
7200	6.0	"	"	2.64	-	891	698.0	"
5400	13.0	"	"	5.89	-	981	711.0	"
7200	12.0	3.5	"	3.92	-	1101	723.0	"
7200	11.0	"	"	3.59	-	1221	734.0	"
7200	11.0	"	"	4.65	-	1341	745.0	"
7200	13.0	"	"	5.49	-	1461	758.0	"
7200	12.5	3.67	"	5.95	-	1581	770.5	"
7200	15.5	3.61	"	7.39	-	1701	786.0	"
7200	16.0	3.61	"	6.27	-	1821	802.0	"
2400	6.0	3.67	"	6.94	-	1941	808.0	"
7200	15.0	"	"	6.10	-	2061	823.0	"
7200	17.5	"	"	7.12	-	2181	840.5	"
7200	16.5	"	"	6.64	-	2301	857.0	"
7200	19.0	"	"	7.63	-	2421	876.0	"

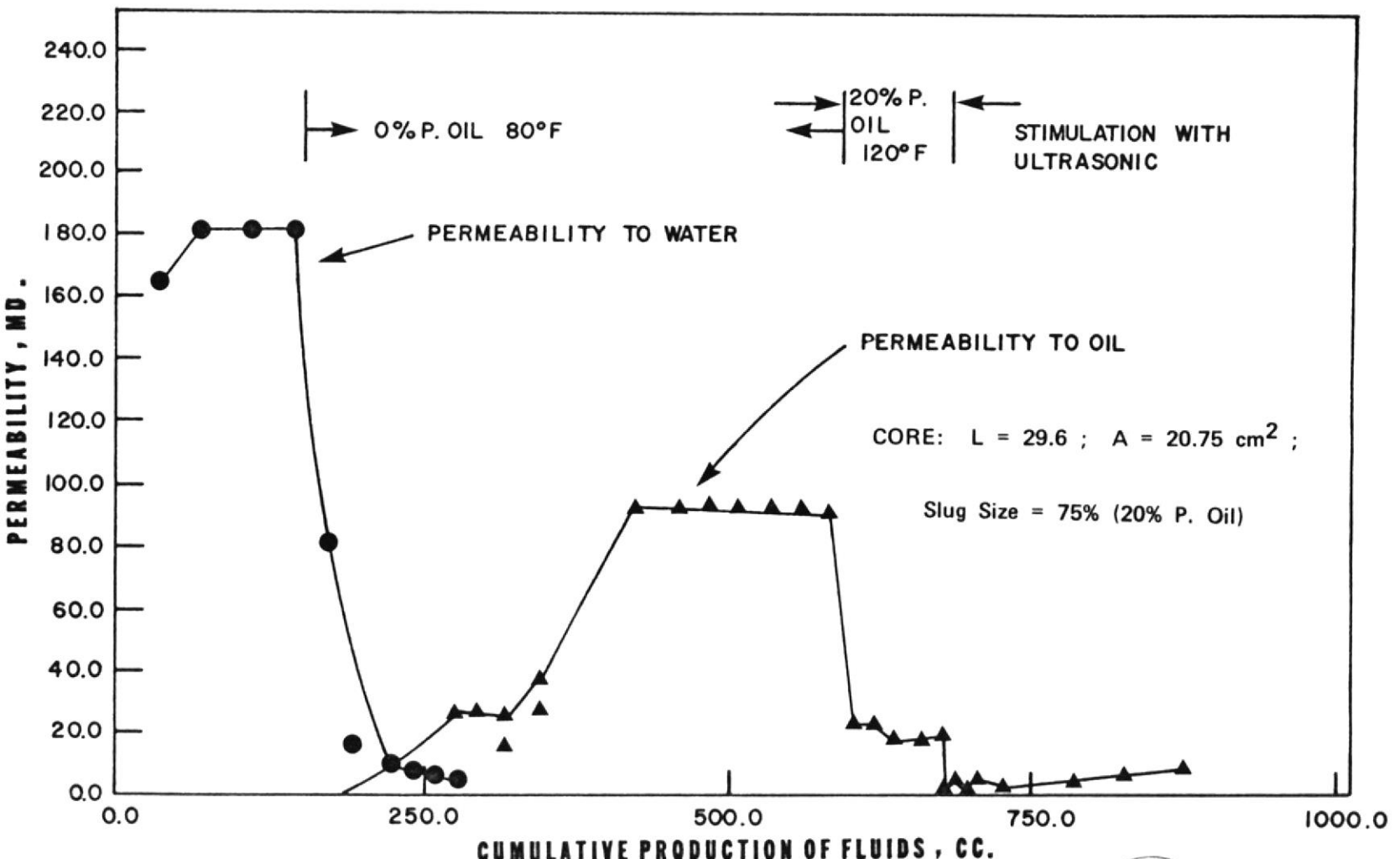


Figure 19. Production History for Run 7

TABLE 14

Summary of Runs Conducted

Run No.	K_w (md)	K_o (md) (1)	Pore Volume	P.in sol. %	Slug size	K_o (2)	K_o (3)	Perm.% recovered after stimu.	Total Run time (min.)	Total time of stimu. with Ultra.
1	19.78	16.45	250.25	10.	24.	0.0	6.53	39.70	2715	240
2	170.	72.2	124.5	10.	84.4	0.0	12.39	17.16	2637	240
3	382.5	152.74	250.25	10.	50.0	0.0	58.10	39.04	1628.33	294
4	175.38	87.83	124.5	10.	14.0	0.0	44.78	51.22	756.60	120
5	363.69	131.3	113.11	20.	25.	0.0	70.25	43.78	2298.	255
6	197.46	67.73	244.85	20.	50.	0.0	9.03	13.03	2389.5	225
7	181.60	92.69	122.84	20.	75	0.0	6.87	7.41	2421.	450

(1) Before injection of P. Oil.
(2) Permeability after plugging with paraffin.
(3) Permeability after stimulation with ultrasonic energy

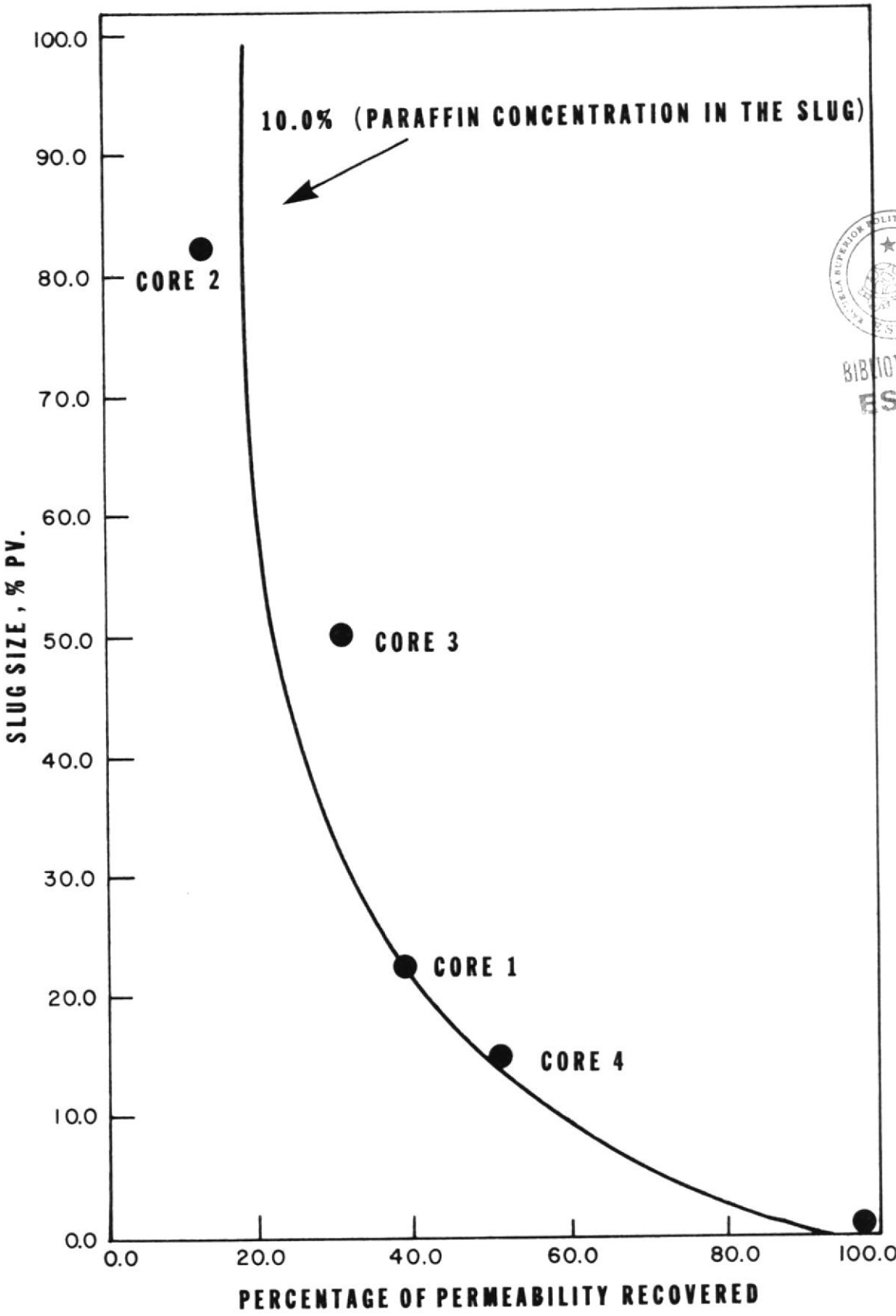


Figure 20. Percentage of K_o recovered as a function of Slug Size, 10%

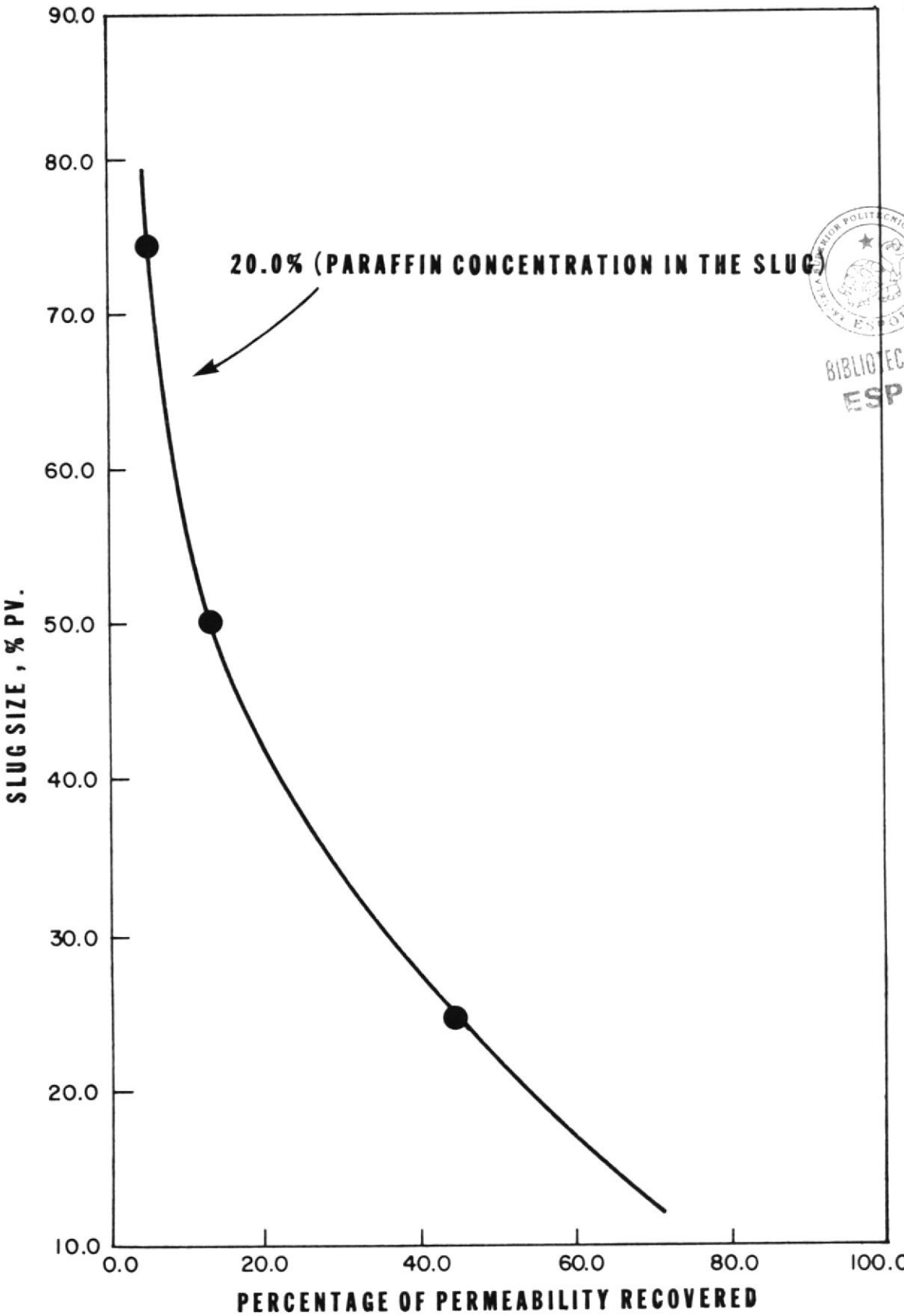


Figure 21. Percentage of K_o Recovered as a Function of Slug Size, 20%

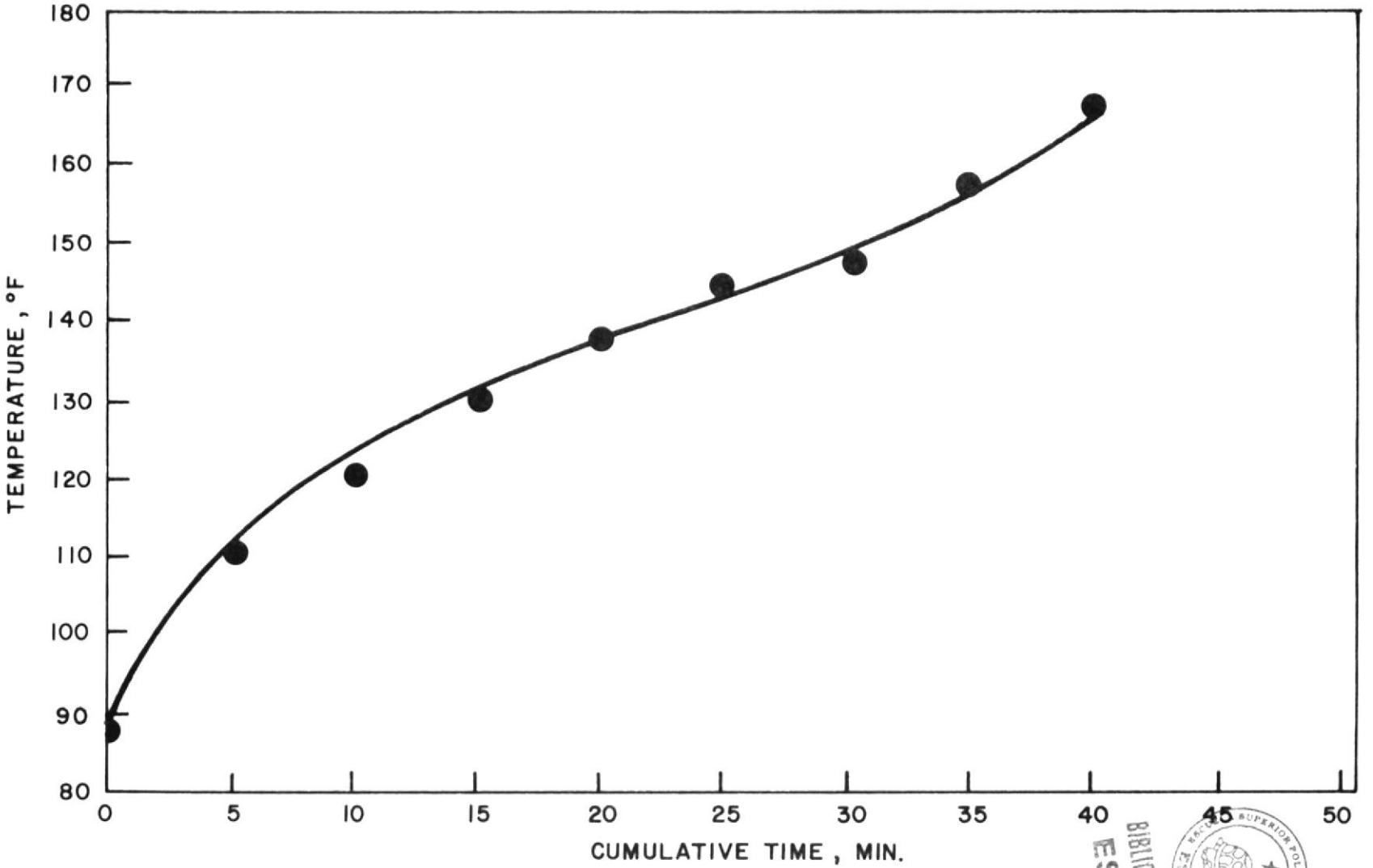


Figure 22. Increase in Temperature due to Ultrasonic Stimulation

and observing the emulsion using a microscope. This could be a major problem since the emulsions formed are very stable.

Wettability Change and Thermal Stimulation

The last set of experiments dealt with thermal stimulation in Oriskany sandstone and Clinton sandstone cores. Three effects were studied, since it was felt that these effects should enter into the success of the thermal stimulation project.

a. The Physical Removal of Paraffin and/or Carbonaceous Material in Fracture Systems and Adjacent Reservoir Rock

The physical removal of paraffin and/or carbonaceous material in fractures systems and adjacent reservoir rock was expected to be the predominant mechanism in any successful stimulation. It is known that the high temperatures existing during the stimulation will burn any such deposits as evidenced by visual inspection of cores baked to 1000°F and many references in the literature to thermal recovery methods. Since these experiments gave better results in removing the paraffin deposits, it was decided to use a thermal stimulation method in the field project. In the laboratory experiments the temperatures used were in the range of 1000-1200°F. At these high temperatures all the paraffin was burned.

b. Fracturing or Alteration of Adjacent Rock

Fracturing or alteration of adjacent rock was another important factor expected to contribute to the success of a thermal stimulation.

Sand cores were fired to 1000-1200°F. A set of tests was conducted to evaluate the overall effects that baking at high temperatures might cause. The only criteria used was a change in permea-

bility of the core during the baking. The results are summarized in Table 15.

The problem encountered using Clinton cores was that even after baking, permeabilities were unmeasurable in the lab equipment used, unless fracturing on a "macro" scale had occurred.

It was established that it was quite easy to initiate fractures along bedding planes in a core. Another possibly more important effect is the extension of existing micro-fractures or the establishment of the same by heating as well as compositional changes in the mineral make-up of the rock. Aktan (1) determined the increase in permeability in Berea and Boise cores when heated to 300°F and 550°F. The increase was due to microfracturing during the heating-cooling cycles. Clinton cores, when heated to 1200°F, were doused in cold water and showed little outward change, unless bedding planes were present in the cores. When this happened the cores cracked along these bedding planes. Oriskany cores, on the other hand, disintegrated when doused in cold water, which implies that the cementing material in the Oriskany cores breaks down under a temperature shock of this magnitude.

These experiments showed the existence of microfractures, as noted by Aktan, in the Oriskany cores which had a good initial permeability (37 md.). This effect was not evident in the Clinton cores.

To study the effect of temperature in the rock structure, pictures were taken using the Electron microscope. These studies were classified as follows:

Oriskany Cores. Frames 1 and 2 of Figure 23 show an Oriskany

TABLE 15

Clinton Cores from Halliburton Sample

Core	Air Permeability before Baking md.	Baking Temperature °F	Air Permeability after Baking md.
1	< 1	900	1.96
2	< 1	1200	2.03
3	< 1	1200	5.45
4	< 1	1200	88.4
5	< 1	900	58.3
6	< 1	1200	56.1

Clinton Cores from Control Well

1	1	1050	< 1
2	1	1050	< 1
3	1	1050	< 1
4	1	1050	< 1
5	1	1050	< 1
6	1	1050	< 1
7	1	1050	< 1
8	1	1050	< 1
9	1	1050	< 1
10	1	1050	< 1
11	1	1050	< 1
12	1	1050	< 1
13	1	1050	< 1
14	1	1050	< 1
15	1	1050	< 1
16	1	1050	< 1

Oriskany Cores (Erie County Pa.)

10H(horizontal	240.9	1000°	584.0
8V(vertical)	160.6	1000°	189.8

core before and after being baked to 1200°F. The dark rectangle (2 cm.) at the bottom right gives the scale of magnification, i.e. 1mm-2cm, a magnification of 20:1. Note the very small pores in the rock before baking and the large open pores after baking.

Frames 1 and 2 of Figure 24 show the same areas of the same cores at a higher magnification 400 μ = 2 cm (500:1). Note in Frame 4 that the largest pore shown is on the order of 200 μ, so that large scale alternation of the rock is taking place during baking at 1200°F.

Frames 1 and 2 of Figure 25 show the same areas of the cores at even higher magnification, 100 μ = 2 cm (2000:1) and 200 μ = 2 cm (1000:1). In the left center of frame 1, one can detect some slight naturally occurring fractures. In frame 2 the wholesale alteration of the rock grains is quite evident.

Frames 1 and 2 of Figures 26, 27 and 28 respectively show another set of analagous pictures from the face of the same core before and after baking. It is obvious that the Oriskany sandstone responds dramatically to the heat treating process by producing large pore systems within the matrix of the treated rock. Flow tests on the cores before and after baking show this behavior but not to the extent these photographs would suggest. Evidently these huge visible pores are not fully interconnected throughout the rock matrix. Permeability increases of two to one have been reported earlier from flow tests. Probably the criterion of small fractures would be the most important effect of the heat treatment.

Clinton Cores. Frames 1 and 2 of Figure 29 are before and after baking photographs of the Clinton cores. Before baking, the cores exhibit almost no porous development on the surface. After baking it is possible to see small pores created during treatment but they are quite scattered and probably not interconnected.

Frames 1 and 2 of Figure 30 are the same areas under higher magnification. There is little apparent difference evident here or under even greater magnification as shown in frames 1 and 2 of Figure 31. The matrix of the Clinton sand does not seem to respond as strongly to the heat treatment as does that of the Oriskany cores. This is why extrapolation of these results from one sand to another are quite risky. Under the circumstances there was little choice in the flow experiments conducted in this study since the Clinton cores were so poor that many tests could not be performed on them. Frames 1 and 2 of Figure 32 and frame 1 of Figure 33 show a large fracture created during the separation of the unbaked Clinton core under different magnifications. It is expected that natural fractures look very much like this in detail.

As reported before, it is possible to create microfractures within the matrix of the Clinton sand.

Figures 33 (Frame 2) and Figure 34 show two of these. Frame 2 of Figure 33 shows a fracture caused by treating at 1200°F at a magnification of 20:1. Frame 1 of Figure 34 is another fracture at a magnification of 20:1. Frame 2 is a 500:1 magnification of the fracture in frame 1. It is felt

that this fracturing effect will be the dominant mechanisms of permeability improvement during the heat treatments. Combined with the splitting effect of cores along bedding planes these fractures through the matrix could easily improve the permeability of the Clinton sand in the vicinity of the wellbore and hydraulic fracture systems by several orders of magnitude.

c. Wettability Changes During Stimulation

After thermal stimulation has removed all fluids from the rock it should be possible to change the wettability characteristics of the rocks. In the field this can be accomplished by injecting nitrogen for a time after burning has stopped to displace the extremely hot gases into the formation near the well. Oil can be displaced into the formation to saturate the dry rock before flowing the well back.

An oil-wet rock theoretically has a higher relative permeability to oil and gas than a water-wet rock. The question is whether or not the wettability change will be permanent.

To investigate the effect of the wettability changes, two Oriskany cores (7V and 8H) were cleaned, dried and saturated with 2% Na Cl brine. The permeabilities to water, oil and gas were measured. These values are reported in Table 16, using a Hassler sleeve flow apparaturs. The permeability to water was quite low compared to air permeabilities on the dry cores which were in the order of 75 md. These cores are quite water sensitive. The measurements are quite anomalous for the water-wet system since relative permeabilities to oil and gas should be lower than that to water. The values reported are the average of about 30 obser-

TABLE 16

Water Wet Oriskany Cores

Core	K_g md	K_o md	K_w md
7V	15.97	1.	6.7
8H	70.2	43.4	16.0

Oil Wet Oriskany Cores

Core	K_g md	K_o md	K_w md
7V	8.1	27.3	1.1
8H	37.3	39.3	11.5

vations and much care was taken to determine that no leakage around the core holder was taking place.

After cleaning and saturating with Sandy Lake crude the flow experiments were repeated with an oil-wet system. In this case the relative permeability behavior was normal with the relative permeability to oil being highest for each core. Comparison to the water-wet system is difficult in view of the anomaly mentioned earlier. These cores were baked to 1200°F for 4 hours and were prepared for the set of runs to study the effect of the stimulation.

A sample approximately 1/8 inch thick was taken from each core for use in the electron microscope. After the next set of flow tests the core was photographed again to sutdy the microfracturing which had occurred. As mentioned earlier, if it is possible to change the wettability of the rocks after heat treatment it might be possible to increase the relative permeability to the gas phase at the expense of the water which is normally the wetting phase.

Two additional cores (12H and 13V) were cleaned, evacuated and dried at 200°C. The permeability to nitrogen was measured in the dry state at 255 and 188 md respectively. The cores were saturated with 2% brine and the permeability to water in this water-wet state was measured as shown in Table 17.

Oil was then passed through the core until the core was at an irreducible water saturation and the permeability to oil was measured at this state. Gas was then introduced and flowed till both the oil and water were at irreducible saturations and its permeability was measured.

The relative permeability to oil and water looked normal for

TABLE 17

Cores 12H and 13V Before Baking at 1200°F

Permeability in Millidarcies

Core	Water-Wet Cores			Oil-Wet Cores			Dry
	K_g	K_w	K_o	K_g	K_w	K_o	
12H	143	78	70	129	43	141	255
13V	90	72	51	55	24	126	188

After Baking

Core	Water-Wet Cores			Oil-Wet Cores			Dry
	K_g	K_w	K_o	K_g	K_w	K_o	
12H	159	75	67	153	61	160	492
13V	153	69	139	218	98	191	583

the water-wet cores (permeability of the wetting phase should be higher). The relative permeability to the gas should theoretically be lower than that to either oil or water but experimentally this did not happen, it may be that continued flowing of the gas has a drying effect on the water-wet cores. The Oriskany sandstone is known to be water sensitive. This effect remains open to investigation.

The cores were then cleaned, dried at 200°C, evacuated and saturated with oil from the Sandy Lake No. 3 well. The permeability to oil was measured in the oil-wet state. Water was then injected until an irreducible oil saturation was established. The permeability to water was then measured. Gas was then flowed until the permeability to gas could be measured at an irreducible oil and water saturation. The oil-water relationship look normal with the permeability to oil (the wetting phase) now being highest in all cases. The gas permeability for the oil-wet case was normal. The cores were then baked at 1200°F and cooled. The same sequence of runs was repeated on the treated cores with the results listed in Table 17.

The absolute permeability to nitrogen in the dry cores was doubled in core 12H and tripled in core 13V. Core 13V exhibited several fractures caused by the heat treatment.

The relative permeability relationships in water-wet core 12H were normal except for the gas permeability. The oil-wet core exhibits normal behavior with increases in relative permeability to the oil, gas and water on the order of 15-17%. This seems small compared to the 200% increase in absolute permeability. Even more

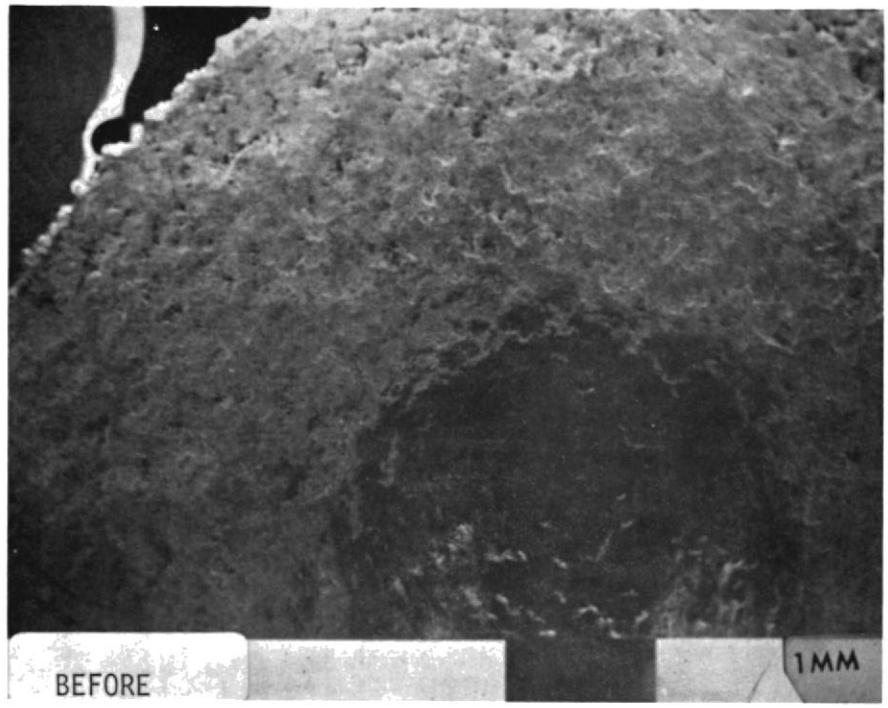
baffling, the 12H water-wet core showed essentially no change after baking.

Core 13V, after baking when water-wet, showed a decrease in relative permeability to water but increases of 175 to 90% to the oil and gas phases. In the oil-wet state after baking, the permeability to the oil phase increased by 50% but the water and gas phase permeabilities increased by about 300%. Although some anomalous behavior was observed during the experiments, the contribution of the heat treatment seems to be its ability to fracture the porous medium. Although the elctron microscope pictures showed some dramatic alteration of the matrix, there seems to be little interconnection of these created pores.

If one looks at the change in oil relative permeabilities due to wettability changes above it can be seen that increases on the order of 35-150% are possible.

It would seem a good idea to incorporate both effects in a field test. Nitrogen should be injected after the burn to cool the area near the fractures and then inject oil to saturate the clean rock.

Coupled with mechanical clean-up of the fracture system it is felt the heat treatment has the best chance of success in the field for the stimulation techniques tested.



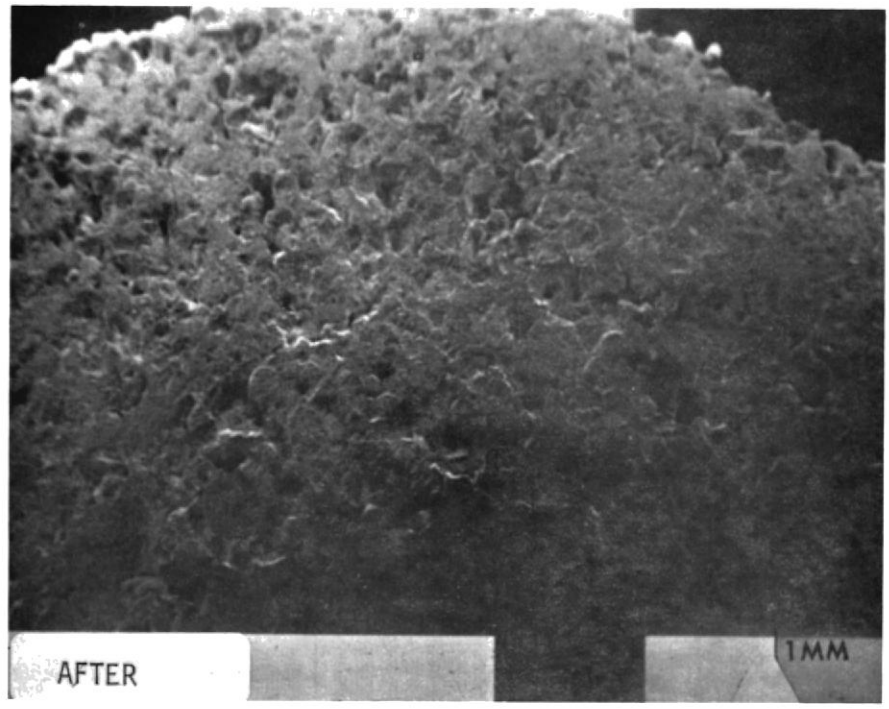
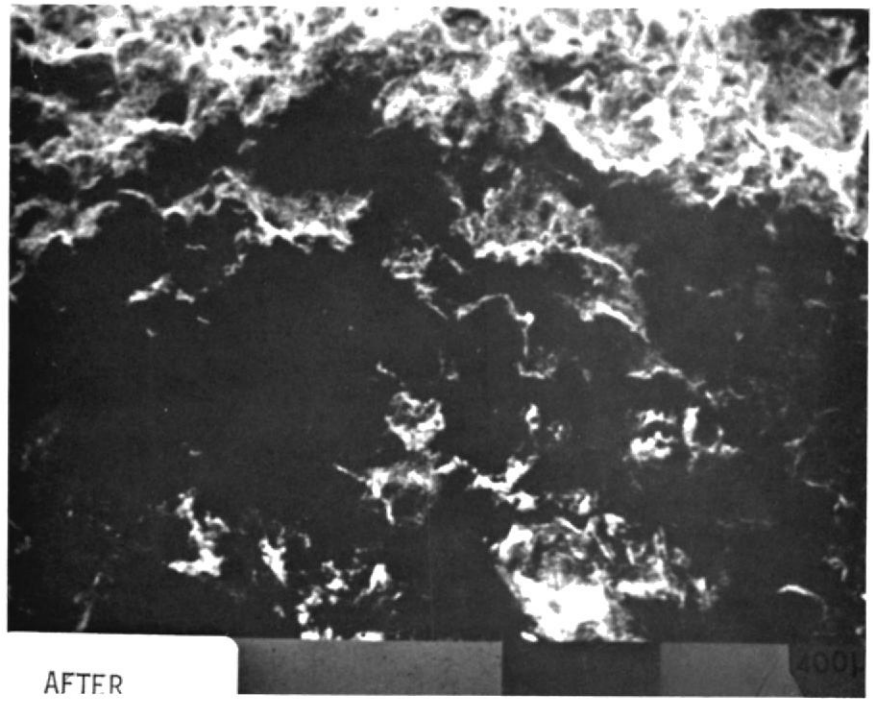


Figure 23. Oriskany Cores Before and After Baking at 1200°F (1MM).



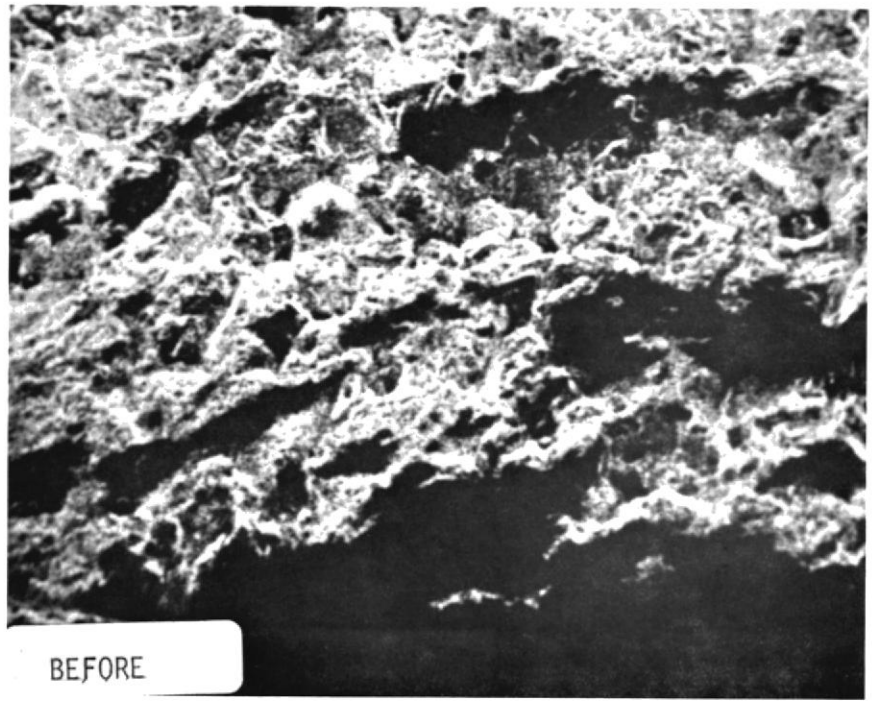


Figure 24. Oriskany Cores Before and After Baking at 1200°F (400 μ).

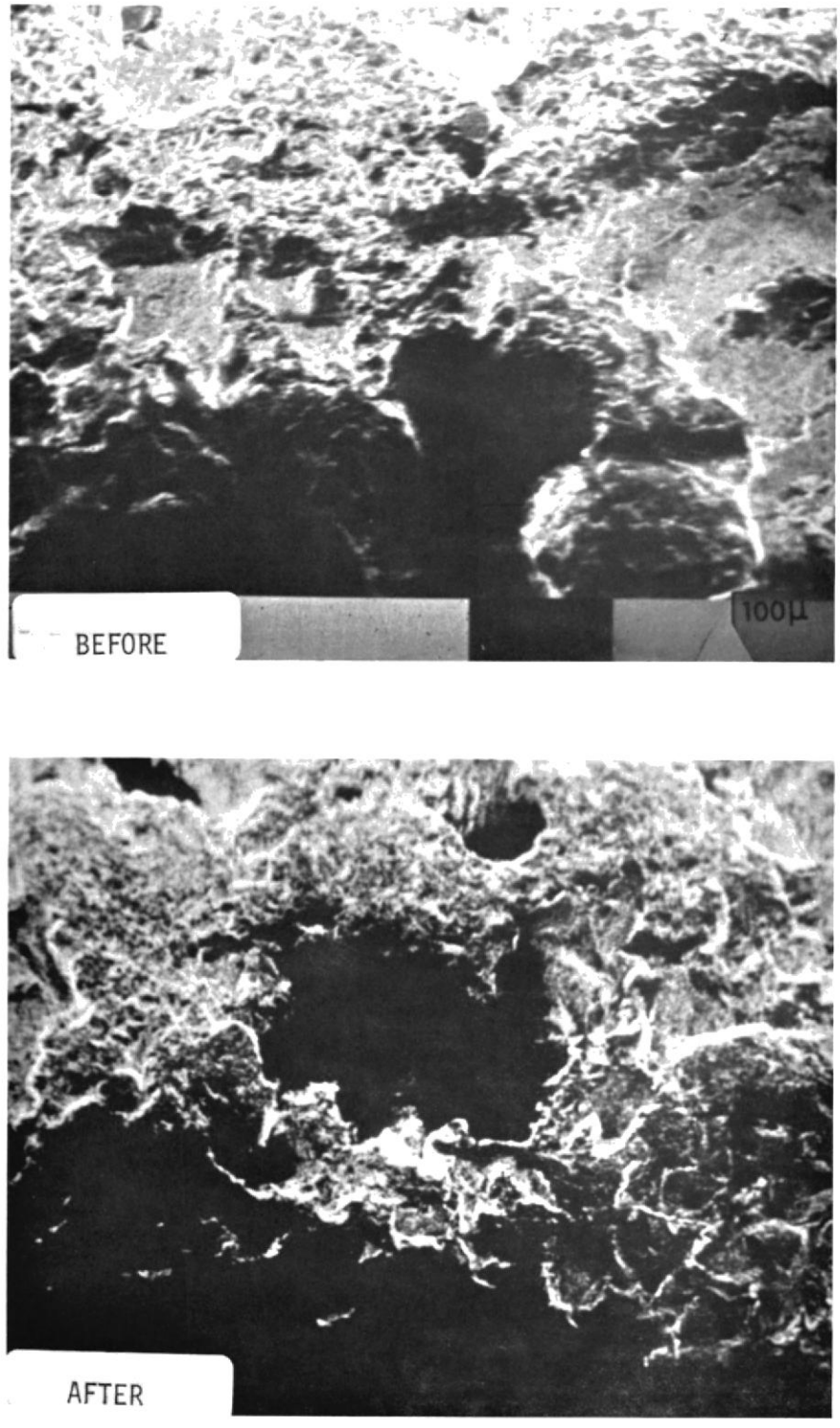
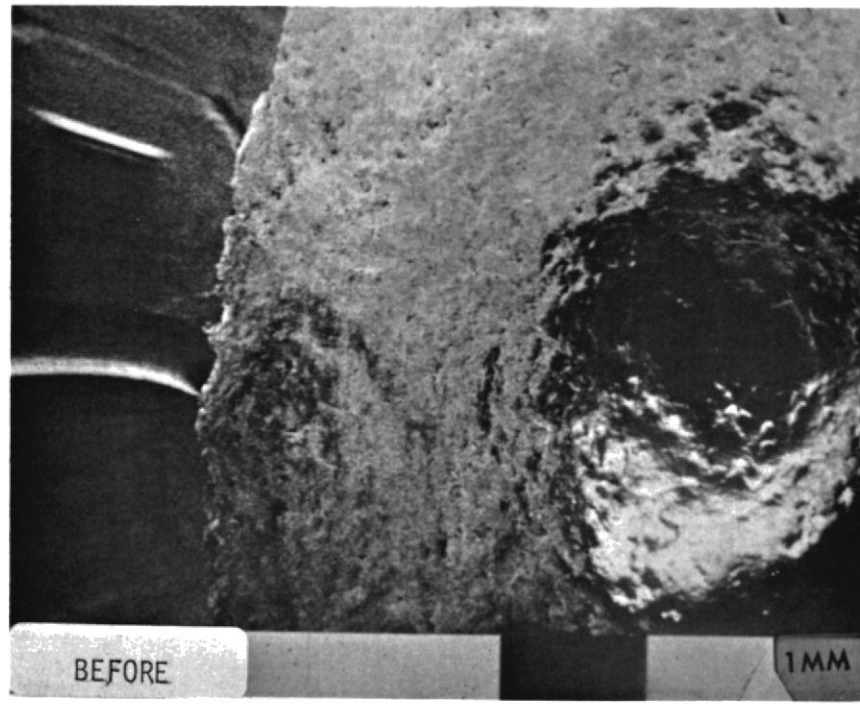


Figure 25. Oriskany Cores Before and After Baking at 1200°F (100 μ).



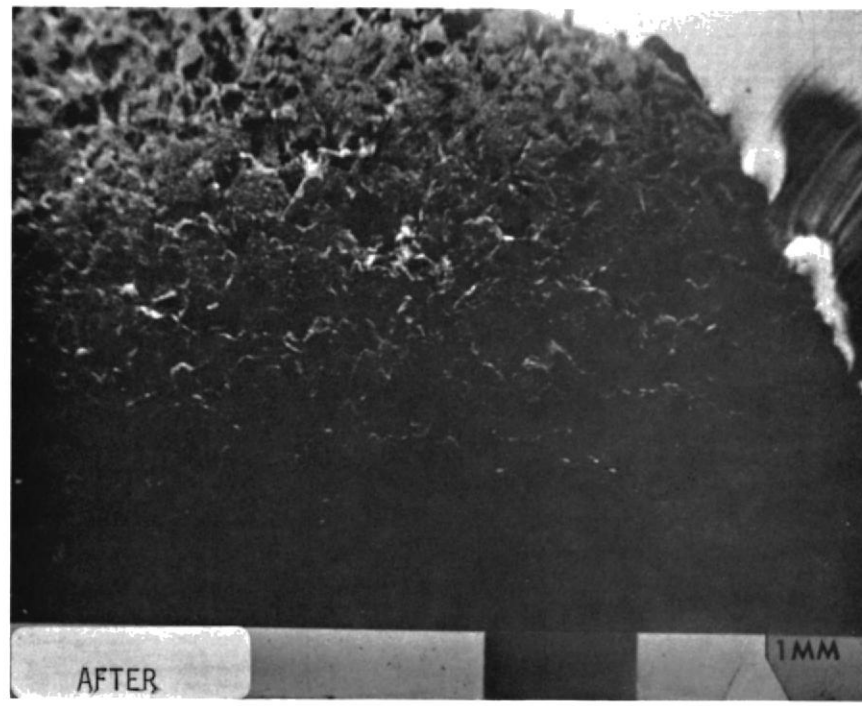
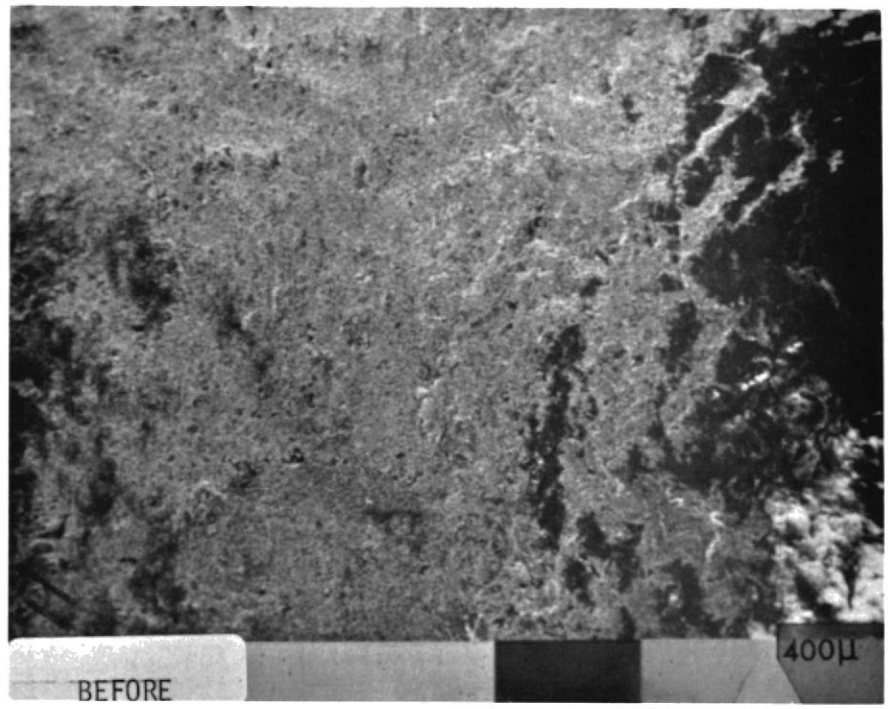


Figure 26. Oriskany Cores Before and After Baking at 1200°F, (1MM).



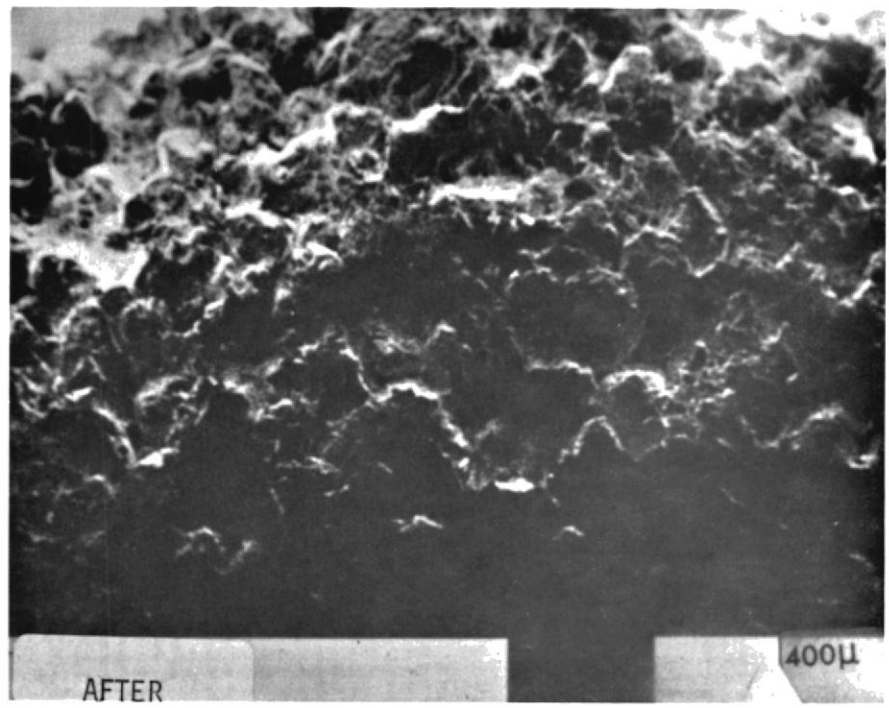
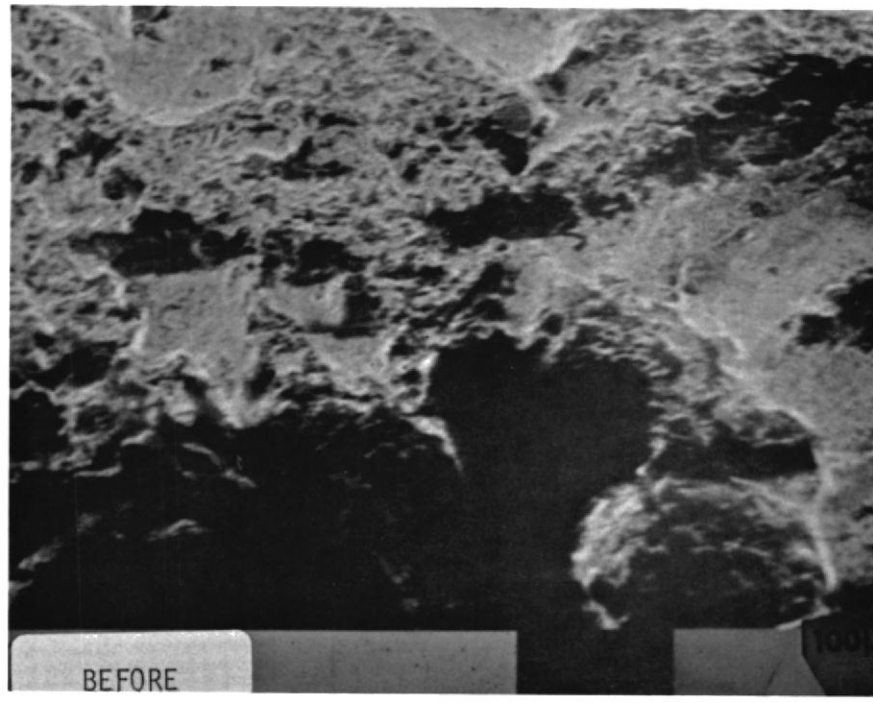


Figure 27. Oriskany Cores Before and After Baking at 1200°F (400µ).



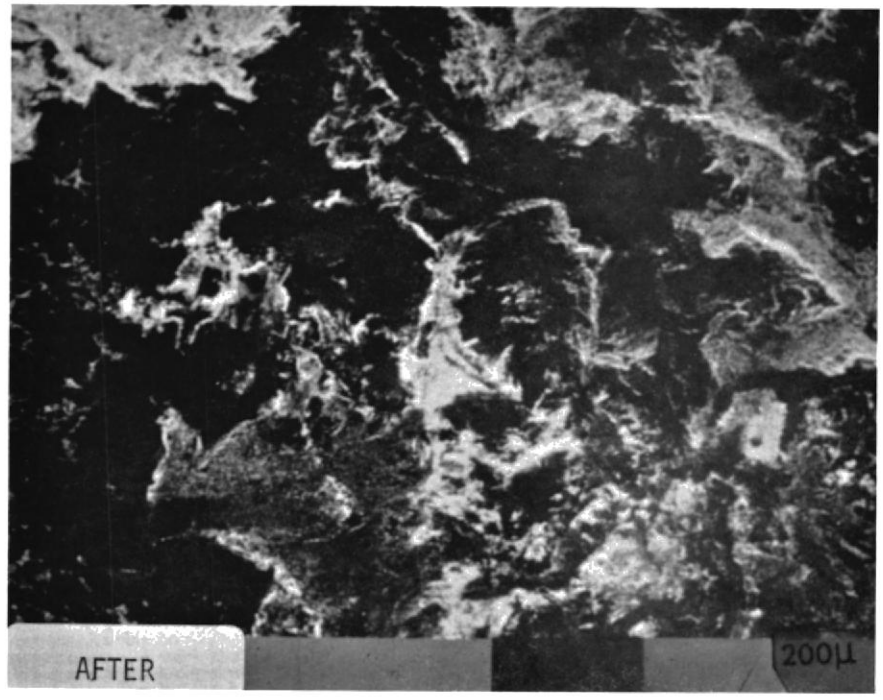


Figure 28. Oriskany Cores Before and After Baking at 1200°F, (100 µ and 200 µ).

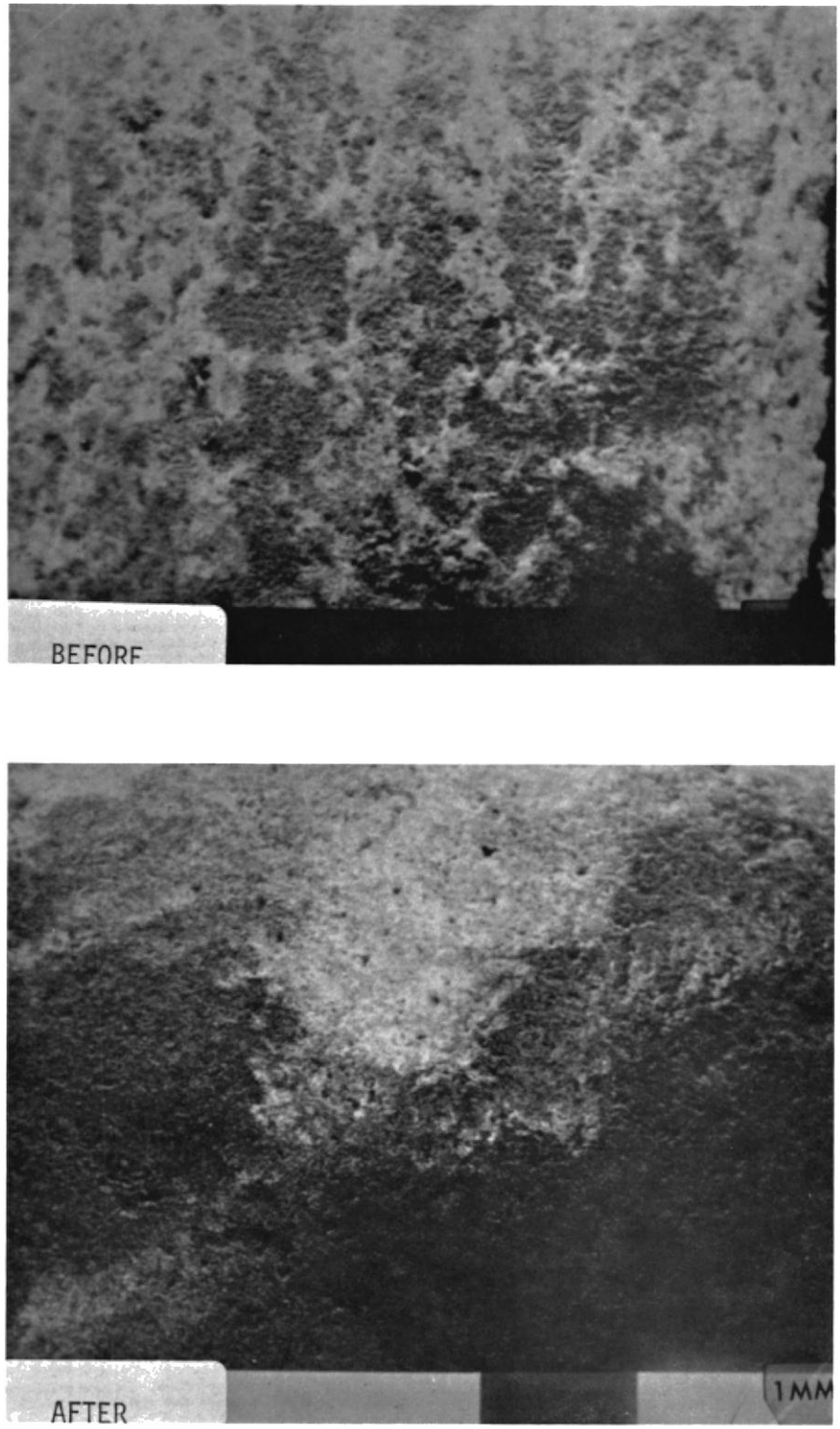


Figure 29. Clinton Cores Before and After Baking at 1200°F (1MM).

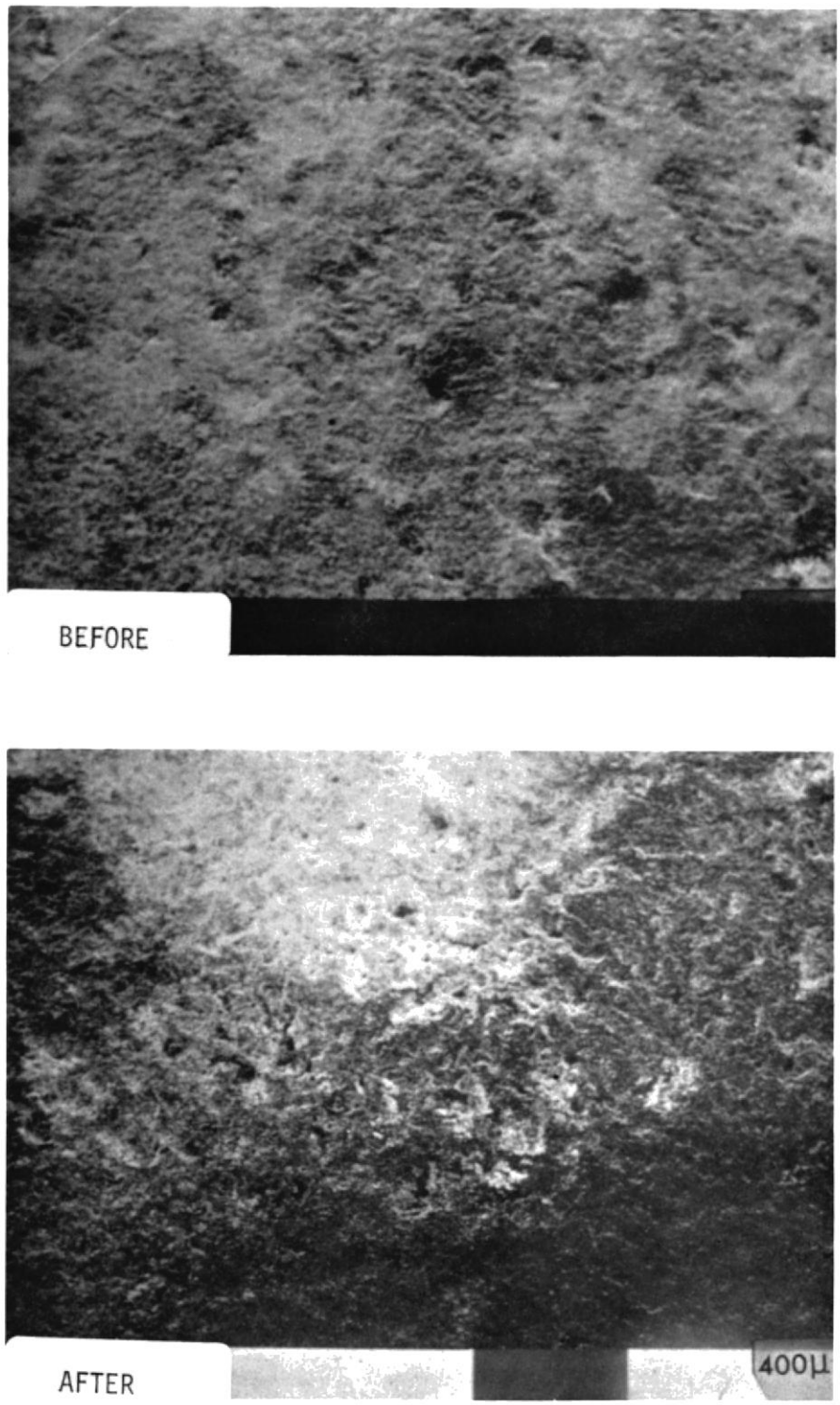
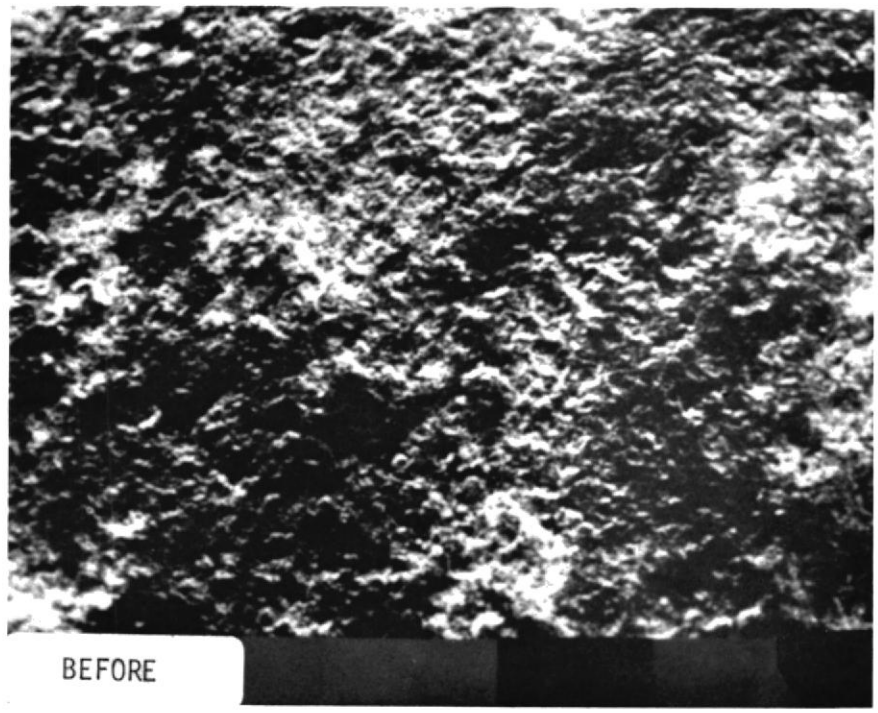


Figure 30. Clinton Cores Before and After Baking at 1200°F (400 μ).



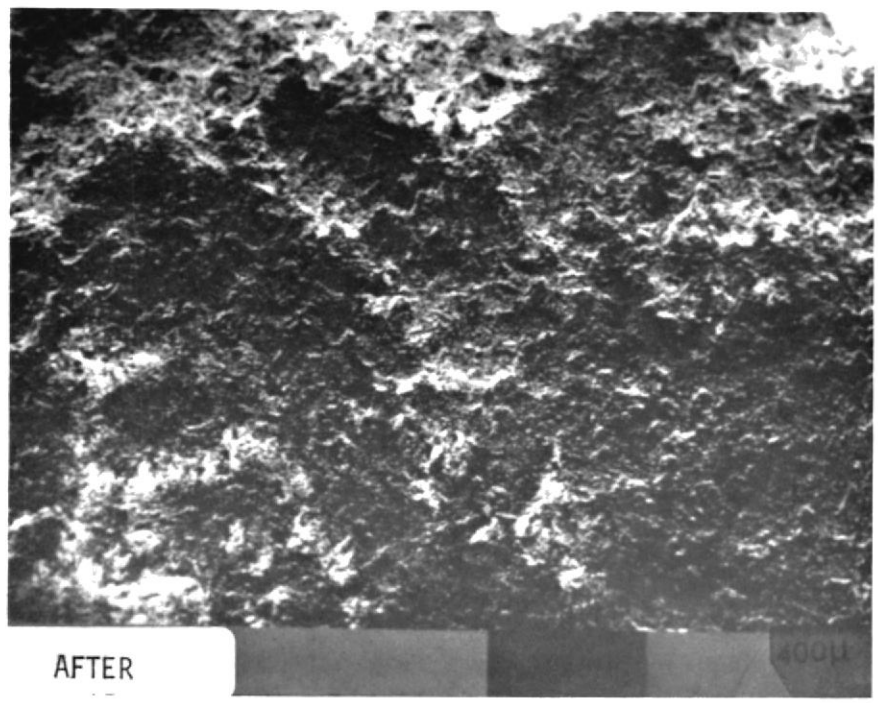
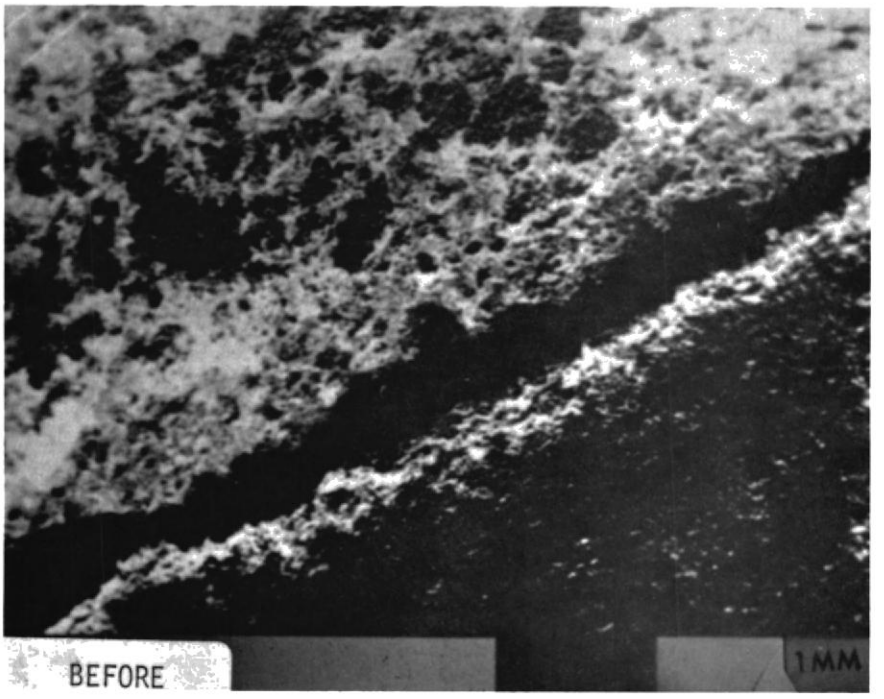


Figure 31. Clinton Cores Before and After Baking at 1200°F (400 μ).



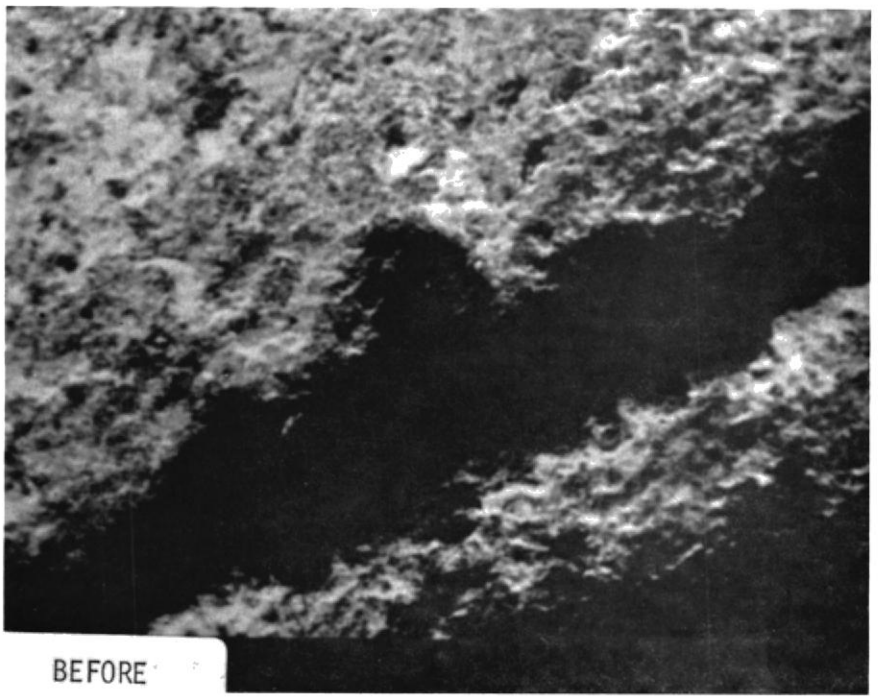


Figure 32. Clinton Cores Before Baking, Natural Fracture System (1M, and 400 μ).

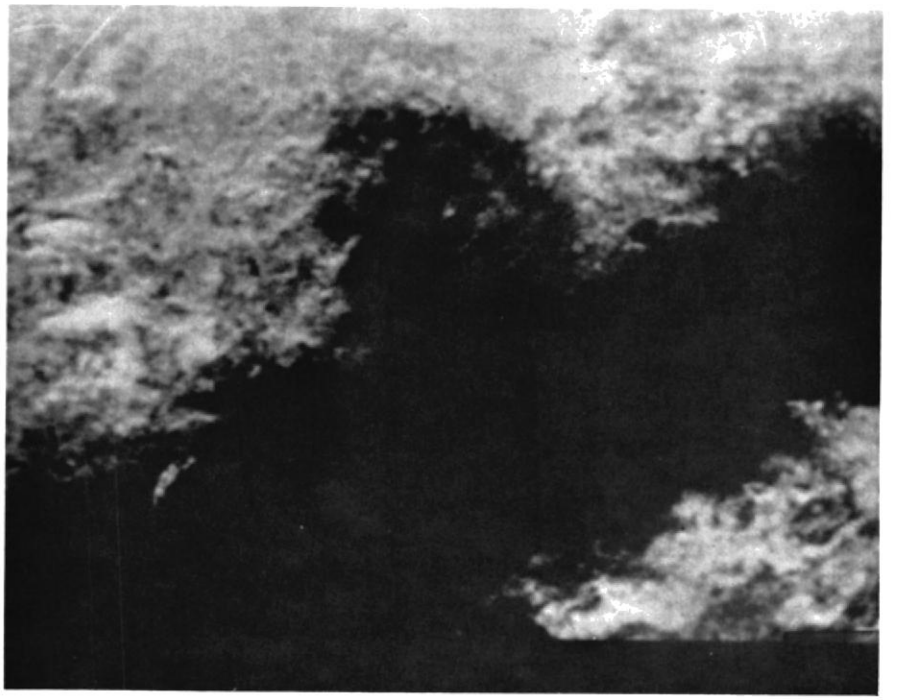
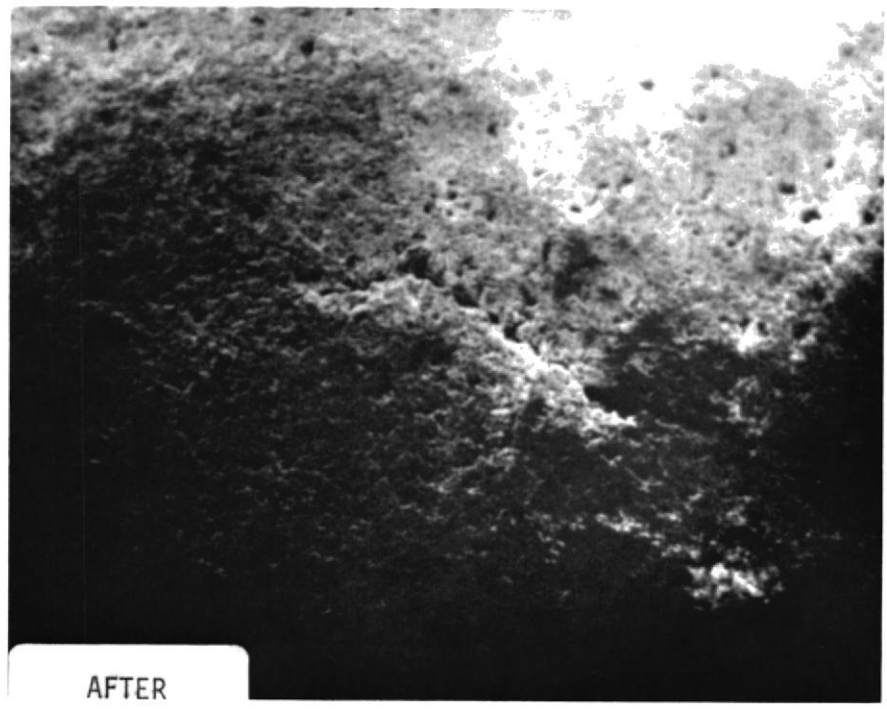


Figure 33. Clinton Core Before Baking, Natural Fracture System (200 μ).



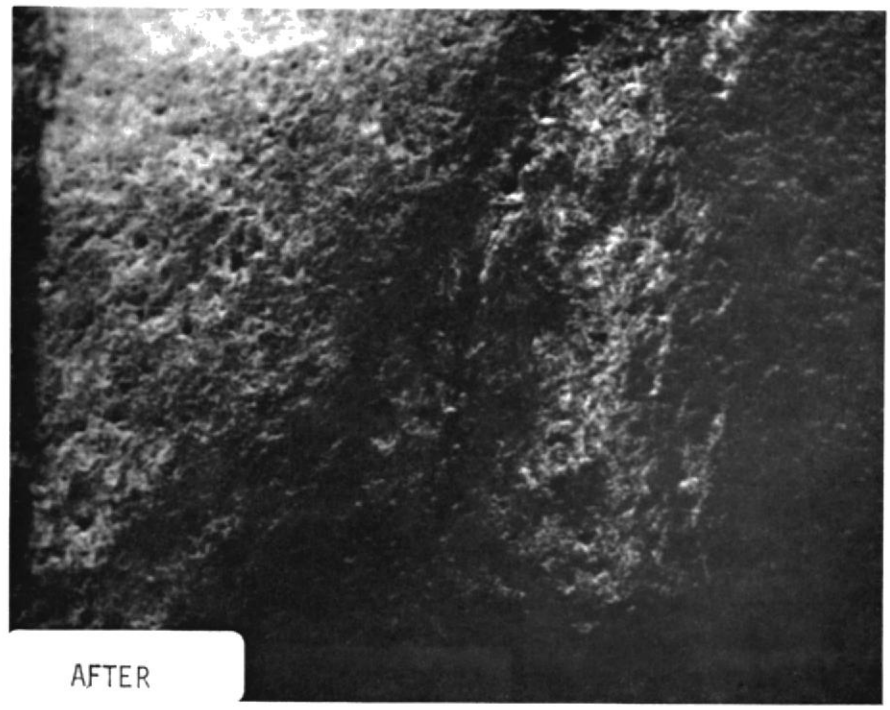


Figure 34. Clinton Cores After Baking, Thermally Induced Fractures (1MM).

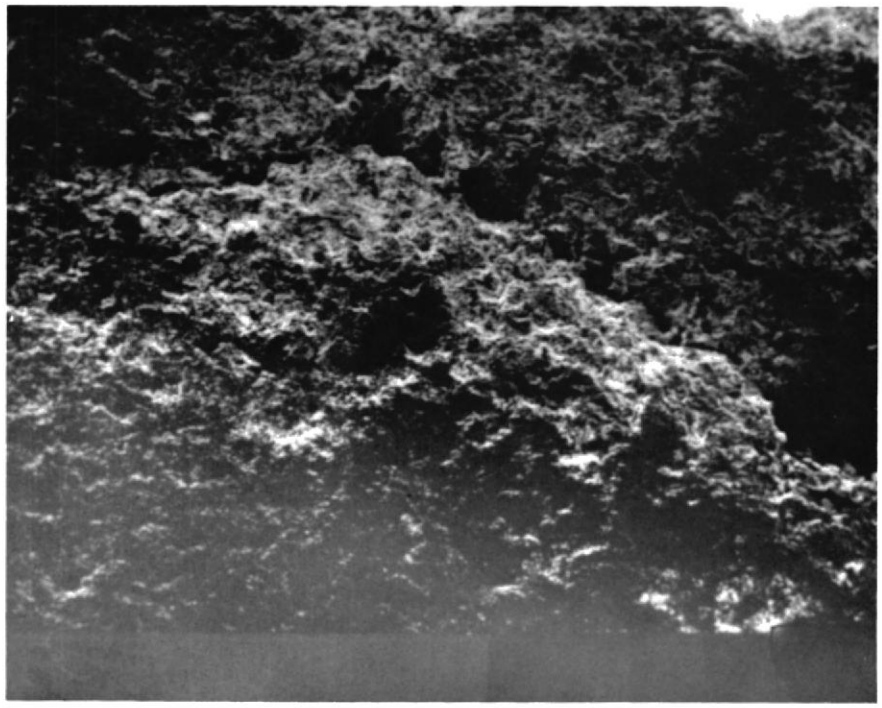


Figure 35. Clinton Core After Baking, Thermally Induced Fractures (400 μ).

CHAPTER VI

FIELD PROJECT

After completing the laboratory experiments, it was decided that the thermal stimulation methods to remove paraffin plugging and to stimulate the formation would have the best chance of succeeding. On this basis it was decided to proceed with the field project oriented toward thermal stimulation as a means of removing paraffins as well as to stimulate the formation.

Control Well

To characterize the Clinton Sand in the local area a control well (Sandy Lake No. 3) was drilled. Figure 36 shows the area in which the control well was located. As can be seen, Sandy Lake No. 3 is located close to other wells. It was hoped in this way to study a group of wells capable of supplying the necessary information to evaluate the effectiveness of the stimulation. The specifications for this well are given in Appendix A.

In order to have detailed information of the formation characteristics as well as accurate data on the fluids and rock properties, many tests and analyses were conducted. A complete analysis of a core penetrating the entire pay zone, including measurements of permeability, porosity and saturations of oil, water and gas at 1 foot intervals was completed. Capillary pressure measurements and relative permeability relationships between the three phases was included for several representative pay sections. The procedures and results obtained for these studies are presented in Appendix B under Special Core Analysis Study.

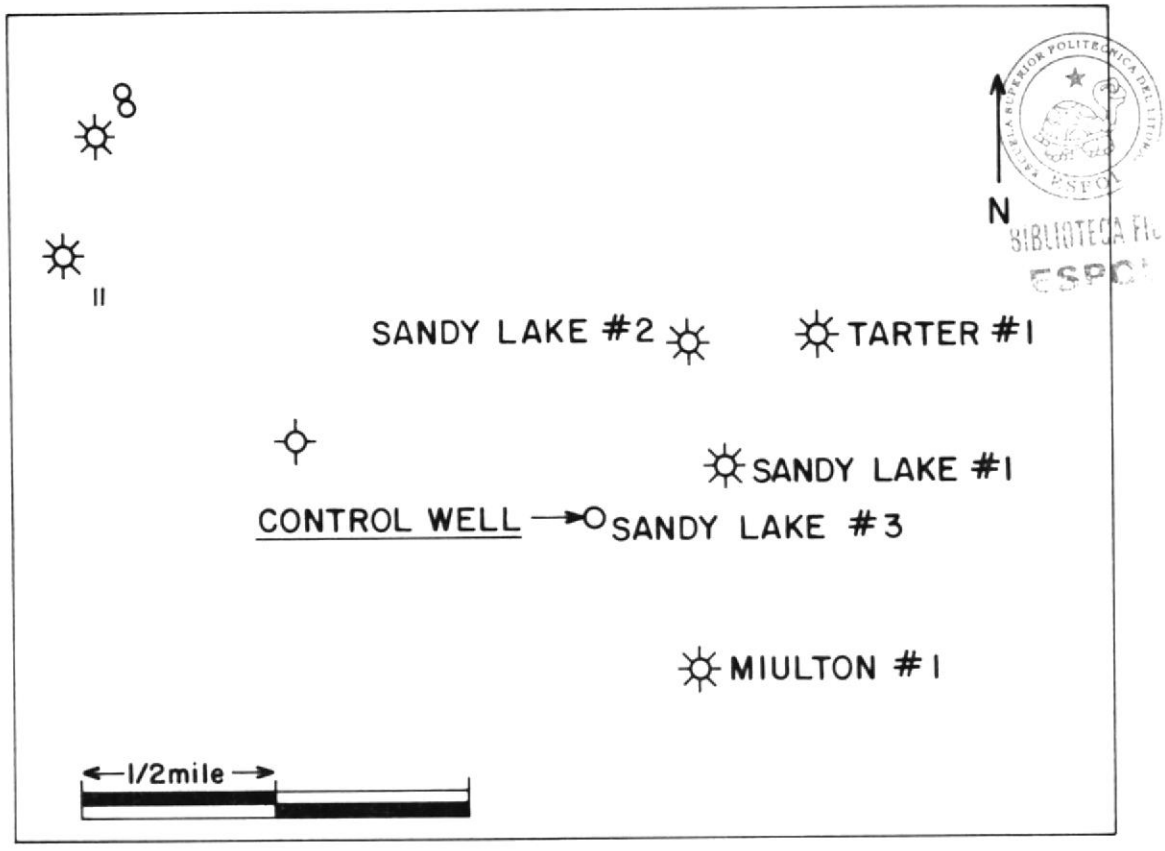


Figure 36. Location of the Wells

A detailed logging program was conducted which included, a temperature log, a gamma ray, neutron, sonic log, dual-laterolog, formation density, 3-dimensional velocity log and a collar locater log.

The analysis of the logs was made by Schlumberger using a computer processed interpretation (CORIBAND).

Analyses were made for formation water, oil and gas, results of these analyses are presented in Appendix B under Fluid Analyses.

The control well was completed open hole, producing through the casing. The well was equipped with accurate, continuous recording gauges to measure flow rates, total production of fluids, pressures and temperatures.

Since the control well did not have sufficient natural flow to perform definitive flow tests, it was fractured in a standard manner for such wells after the logging program. Modified Isochronal and pressure buildup tests were run after fracturing to define the insitu reservoir parameters. The procedures followed are presented in Appendix A under Well Test Procedures.

The Isochronal curve for the Sandy Lake No. 3 is presented in Figure 37. The original bottom hole pressure was about 1200 psi and this curve would indicate a true absolute open flow potential of only about 200 MCF/D. Actually, rates as high as 2000 MCF/D were sustained for an hour time but this is the result of the compressed gas in the well and the gas produced from near the fracture systems close to the wellbore. The stabilized points were measured after flow times of 3 days when the transient pressure behavior had moved out beyond the limits of the fracture systems. The exponent n (the reciprocal slope of the curve) has a value of 1.17. This indicates that the test may

not be too reliable since it falls outside the theoretical range of .5-1.0. The data for Figure 37 is given in Table 18. The AOF reported corresponds to 1158 psia.

The pressure buildup test run on the control well is presented in Table 19 and Figure 38. The value of permeability (approximately .02 md.) reported in Figure 38 was calculated using,

$$K = \frac{162.6\ qg\ \mu\ Bg}{mh} \qquad (6.1)$$

where

K = permeability, md.

qg = flow rate of gas, B/D

μ = gas viscosity, cp

Bg = gas formation factor, res Bbl/STB

m = slope of the stabilized part of the curve, psi/cycle

h = formation thickness, ft.

After Sandy Lake No. 3 was fractured, the well was opened to production. Table 20 and Figures 39 and 40 show the production history of the well. When production started on September 1, 1975, the well head pressure was 1150 psig. Nine days later, the pressure was down to 875 and on September 23, the well head pressure was stabilized at 115 psig. This pressure was nearly constant through the whole production history (April 12, 1976). This behavior is typical of the wells of this area. This sharp drop in pressure may cause paraffin to precipitate and reduce even more the flow capacity of the well.

Offset Wells

Sandy Lake No. 2 and Tarter No. 1 were selected as offset wells.

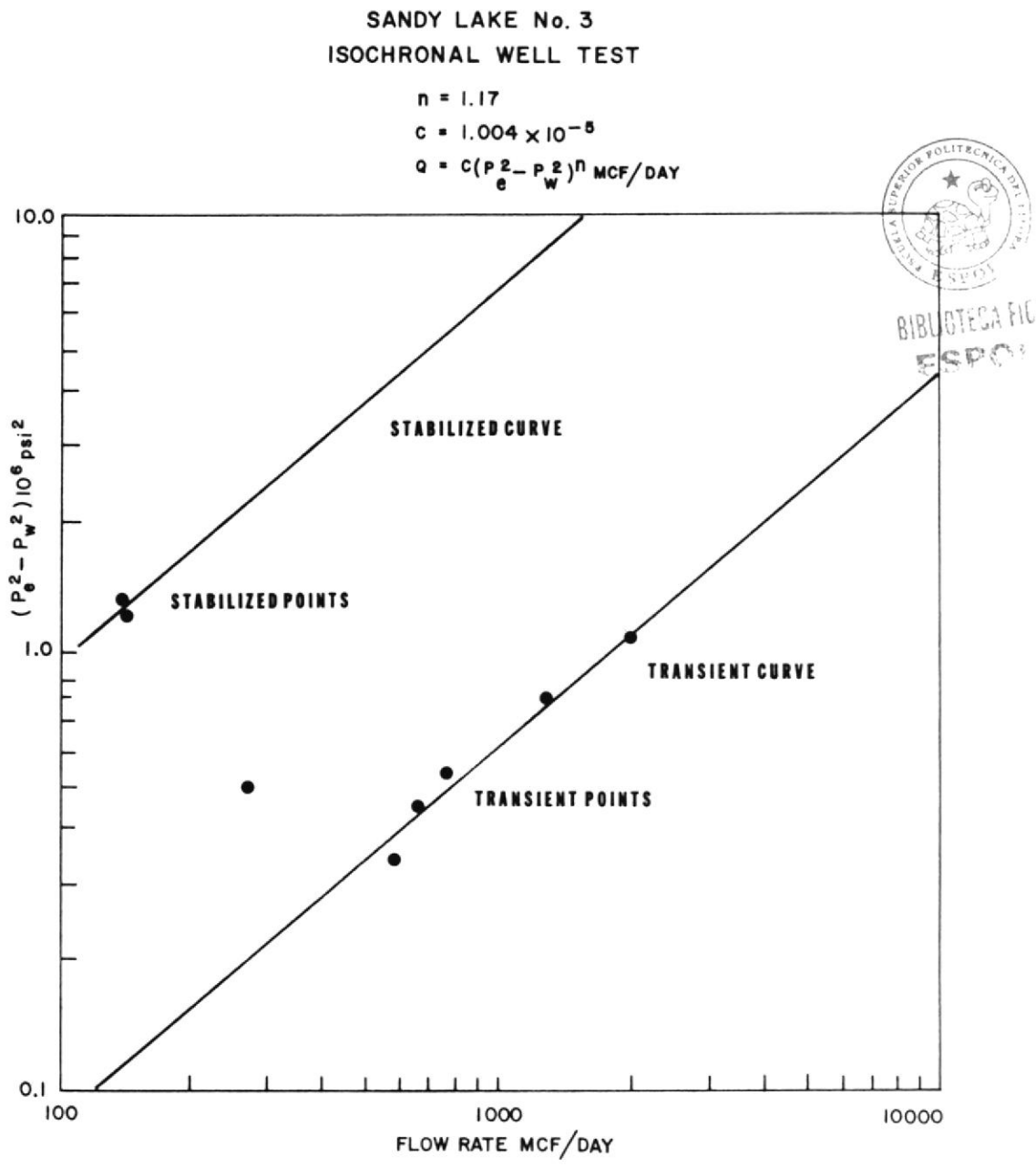


Figure 37. Sandy Lake No. 3, Isochronal Well Test

TABLE 19

Pressure Buildup Test, Sandy Lake No. 3

Δt (hrs.)	$\frac{th+\Delta t}{\Delta t}$	bhp (psi)	Δt (hrs.)	$\frac{th+\Delta t}{\Delta t}$	bhp (psi)
0	∞	150	18	55	762
1	983	275	19	53	773
2	492	345	20	50	783
3	328	390	21	48	793
4	246	431	22	46	810
5	197	470	23	44	820
6	165	502	24	42	830
			27	37	860
7	141	525	30	34	895
			33	31	940
8	124	548	36	28	962
			39	26	983
9	110	570	42	24	1020
			45	22	1043
10	99	598	48	21	1059
			51	20	1082
11	90	625	54	19	1100
			57	18	1122
12	83	642	60	17	1133
			63	16	1133
13	76	665	66	16	1139
			69	15	1139
14	71	681	72	14	1139
			78	13	1145
15	66	710	84	13	1150
			90	12	1161
16	62	732			
17	59	750			

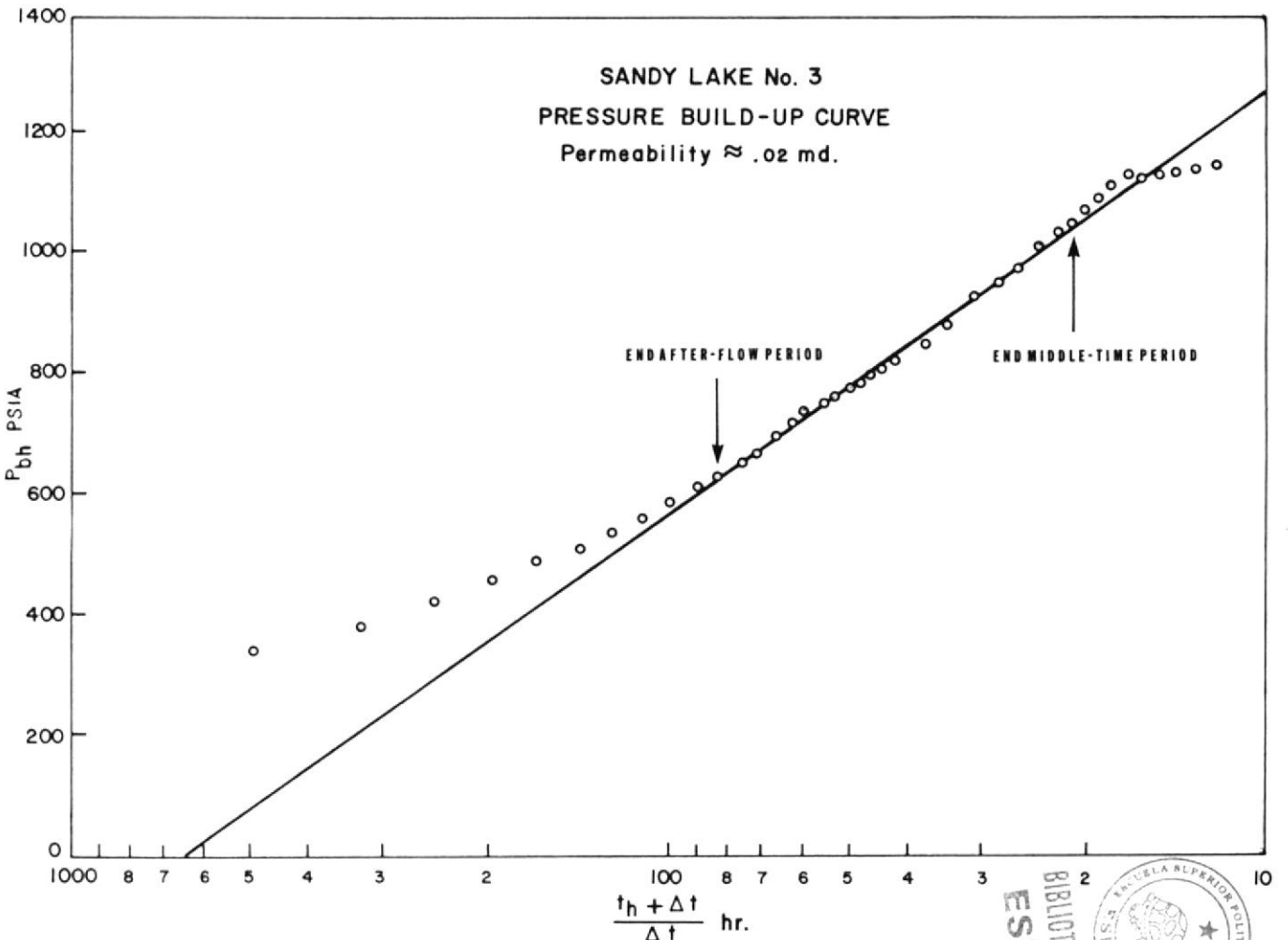


Figure 38. Sandy Lake No. 3, Pressure Buildup Curve

TABLE 20

Production History for Sandy Lake No. 3

Date	Gas Produced (MCF)	Cumulative Gas Prod. (MCF)	Oil Produced (BBL)	Cumulative Oil Prod. (BBL)	Water Produced (BBL)	Cumulative Water Prod. (BBL)	Pressure (psig)
1975							
9/1- 9/30	3612.3	3612.3	274.1	274.1	599.8	599.8	115
10/1-10/31	2180.7	5343.0	112.9	387.0	61.40	661.2	115
11/1-11/30	2838.1	8181.1	74.6	461.6	46.7	757.9	125
12/1-12/31	2606.7	10787.8	100.0	561.6	32.8	790.7	115
		10787.8		561.6		790.7	
1976							
1/1- 1/31	2517.5	13305.3	51.2	612.8	36.6	827.3	115
2/1- 2/29	775.5	14080.8	87.0	699.8	98.0	925.3	155
3/1- 3/31	2932.4	17013.2	130.8	830.6	98.1	1023.4	125
4/1- 4/12	668.6	17681.8	52.0	882.6	34.0	1057.4	125
4/12- 4/30	1378.8	19060.6	35.1	917.7	36.1	1093.5	125
5/1- 5/17	1042.1	20102.7	54.3	972.0	55.0	1148.5	125
5/8- 5/31	1370.1	21472.8	31.0	1003.0	23.0	1171.5	130
6/1- 6/14	1262.1	22734.9	28.0	1031.0	18.0	1189.5	125
6/14- 6/30	1013.4	23748.3	35.0	1066.0	16.0	1205.5	140
7/1- 7/19	1184.3	24932.6	49.	1115.0	11.0	1216.5	180

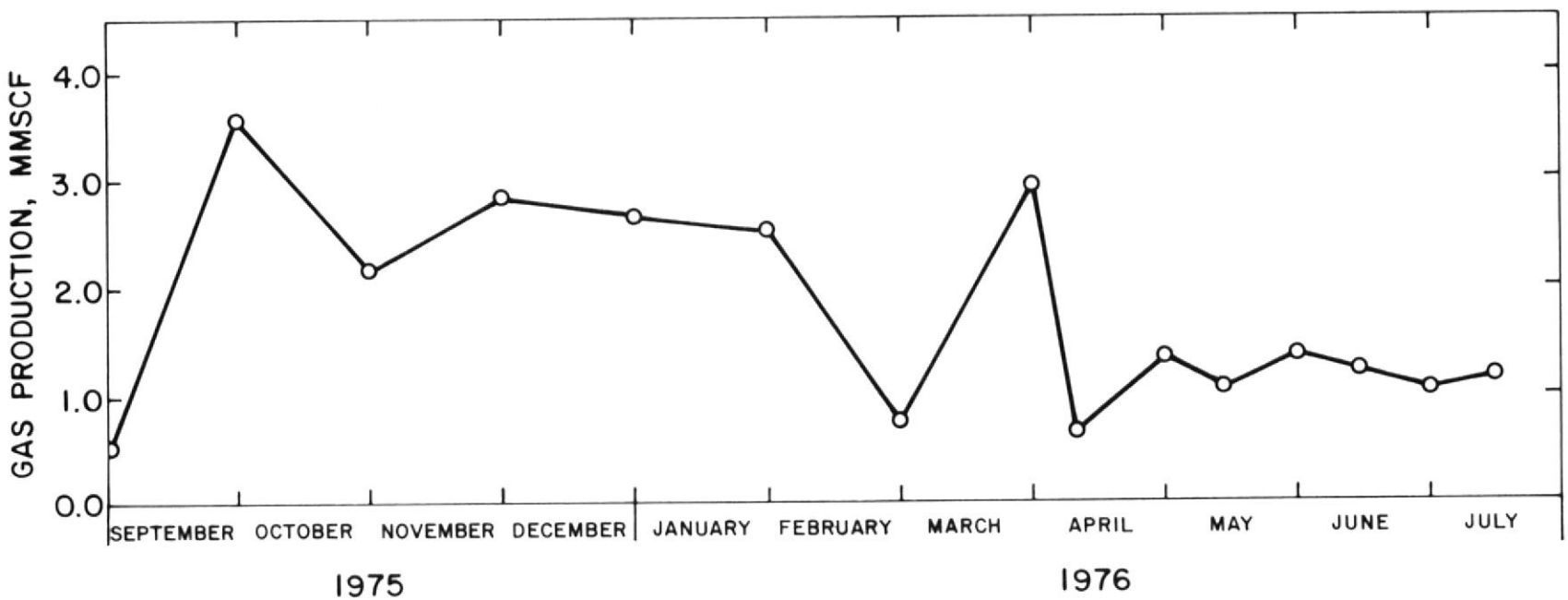


Figure 39. Gas Monthly Production, Sandy Lake No. 3.

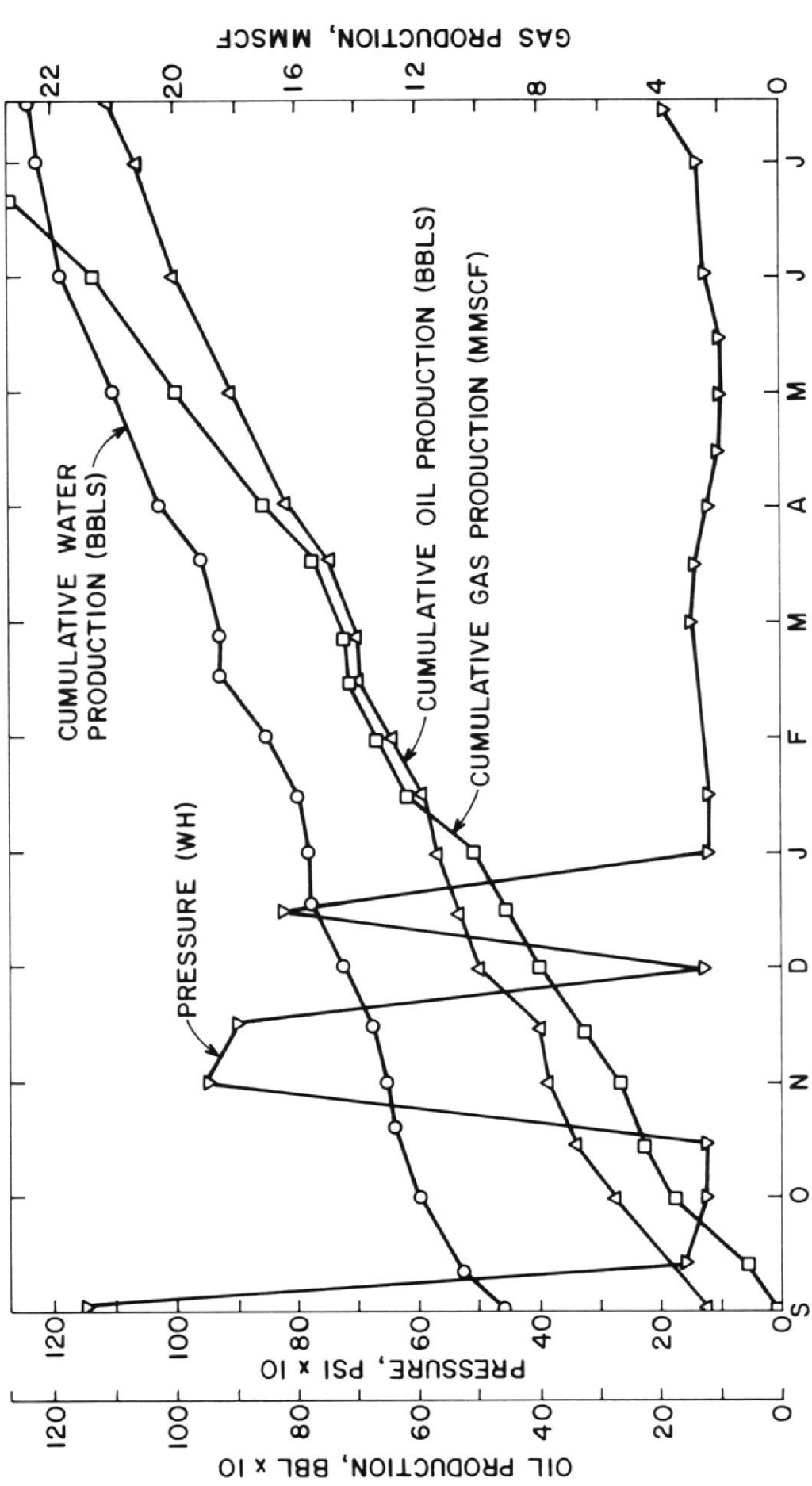


Figure 40. Production History for Sandy Lake No. 3.

It was felt that these two wells were the most promising for the stimulation tests on the basis of their position and production history. For example, pressure buildup tests conducted in Sandy Lake No. 2 suggest well damage exists and the potential for improving this well was high. Also, the permeability in the area of these wells seems to be better than near the other wells tested and is in the range of 0.3 md.

Table 21 gives the characteristics of these two wells and Table 22 shows the completion details.

The following operations were conducted in these wells:

1. Cleaning and conditioning
2. Modified Isochronal tests
3. Pressure buildup tests
4. Thermal stimulation
5. Blow back of air and burned gases
6. Modified Isochronal tests after stimulation.
7. Pressure buildup after stimulation.

Isochronal tests were used to determine the requirements for the air compressor to be used in the thermal stimulation of these wells, and to provide a comparison of the wells' deliverability before and after stimulation.

Thermal Stimulation

With the well system properly defined the experimental thermal stimulation project was designed. The basic idea of the treatment was to correct or improve well performance by creating a high temperature gradient from the well to the surrounding formation. This increase in temperature should accomplish several things in order to be a success-

TABLE 21

Characteristics of Offset Wells

	Sandy Lake No. 2	Tarter No. 1
	2454	2441
Formation		
Sand Thickness (50%) - feet	52	44
Sand Thickness (75%) - feet	32	28
Average Porosity - %	14	8
Fracturing Treatment		
Total Volume Water - bbls	1231	527
Total Sand (20/40) - lbs	42300	14250
Nitrogen - SCF	149000	None
Acid Spearhead - Gals.	500	500
Breakdown Pressure - Psi	2000	2600
Average Flushing Pressure - Psi	2200	2100
Average Injection Rate - Bbls/min.	46.6	39.0
Instant Shut Down Pressure - Psi	1100	700
Production		
Open Flow Before Frac. - MCF/day	Show	Show
Rock Pressure Before Frac. - Psig	1325	1300
Open Flow After Frac. - MCF/day	5036	1365
Rock Pressure After Frac. - Psig	1370	1370
Initial Delivery Date - Psig	1-10-68	8-29-67
Total Accum. Gas (August 1975), MMCF	183	170
Present Daily Rate - MCF	39	38
Total Accumulative Oil - Bbls.	1830	1227
Reserves		
Original Projection, MMCF	500	385
Revised Projection as of August 1975, MMCF	283	370
Estimate Remaining, MMCF	100	100

TABLE 22

Completion of Offset Wells

Sandy Lake No. 2

7 inch surface casing 555 KB, wt. 20#, 225 sks. of cement
4 1/2 inch casing @ 4419 ft. wt. 11.6#, 150 sks. of cement
1/9 inch tubing @ 4292 ft., wt. 2.75#
Total depth after completion, 4415 ft.
Total depth, 4420 ft.
Gas at 4303 - 4338 ft.
Oil at 4328 ft.

Perforated	No. Holes	Perforated	No. Holes
4303-4305	3	4321-4324	4
4310-4311	2	4332-4334	3
4315-4317	3	4376	1

Tarter No. 1

4 1/2 inch casing @ 4350
Total depth, 4425

Perforated	No. Holes
4331-4332	2
4285-4286	2
4305-4315	11

ful treatment. The high temperature in the well bore and in the surrounding fracture system must remove immobile hydrocarbon materials that may be plugging the pores and fractures of the producing zone. Since the formation involved (Clinton Sandstone) is known to be a very tight rock, sharp temperature gradients and changes in temperature must cause thermal fractures. Since the formation had already been hydraulically fractured, only a small increase in permeability was expected because of the near-well, high temperature micro-fracturing of the rock matrix. Since the temperatures developed were on the order of 900°F-1200°F, permanent dehydration of montmorillonite is expected to occur. In this way wellbore damage in this water sensitive formation could be corrected. The water production is not significant for this formation, but the high temperatures could help in removing residual oil and water from near the wellbore improving in this manner the permeability to gas. Naturally, these effects would be confined to a small radius (several feet) around the wellbore.

Actually, most of the improvement in well performance should come from asphaltic and paraffin clean up. This clean up should occur not only in the well bore but the fractures and formation should be cleaned up for a distance of several feet around the well. The paraffin should be melted and driven back in solution by the hot gases. The effectiveness of the treatment was to be determined by pressure buildup and isochronal tests to be conducted before and after the thermal stimulation treatment. The equipment used and procedure followed is described in Appendix C.

Thermal stimulation of East Ohio Gas, Sandy Lake No. 2 was initiated by TOR Developments on March 26, 1976. A down-hole gas burner

system was utilized to heat the formation. The procedure was to inject methane with a small (12 MCFD), high pressure, gas compressor down the tubing to a heat-shield where the gas was mixed with air that was simultaneously being injected down the easing. The location of the heat-shield is shown in Figure 41. The perforated interval is 4302 ft. to 4335 ft. Hourly data taken during the gas burner operation was plotted in Figure 42 and shows air rate, gas rate and the well-head gas injection pressure. The average theoretical temperature of the burner calculated from these data is also plotted. Ignition was accomplished at 11:23 on March 26, 1976, after one run with the igniter tool. During the five days of burner operation the air rate was maintained at 410 MCFD (initially) and increased to approximately 470 MCFD after the first three days of operation. The gas injection rate was 6 MCFD initially and was adjusted during the five days of burner operation to maintain an air-gas ratio of 56. Sharp decreases in the air rate on March 28, 29 and 30, were due to problems with the pilot valve unloading and throttling problems on the air compressor. An attempt to check burner operation on March 29 produced unsatisfactory results and a second ignition run resulted in the burner assembly sticking to the seat of the heat-shield. Attempts to free the burner resulted in the tool falling through the heat-shield and the wire line melting or oxidizing with subsequent loss of the entire burner assembly. This was, however, a positive indication of burner operation in the desired temperature range.

Another positive indication of ignition was an increase in bottom hole pressure. On Figure 42, the gas injection pressure is shown to have increased from 595 psi at the beginning of the ignition to 1370 psi when burner operation was terminated.

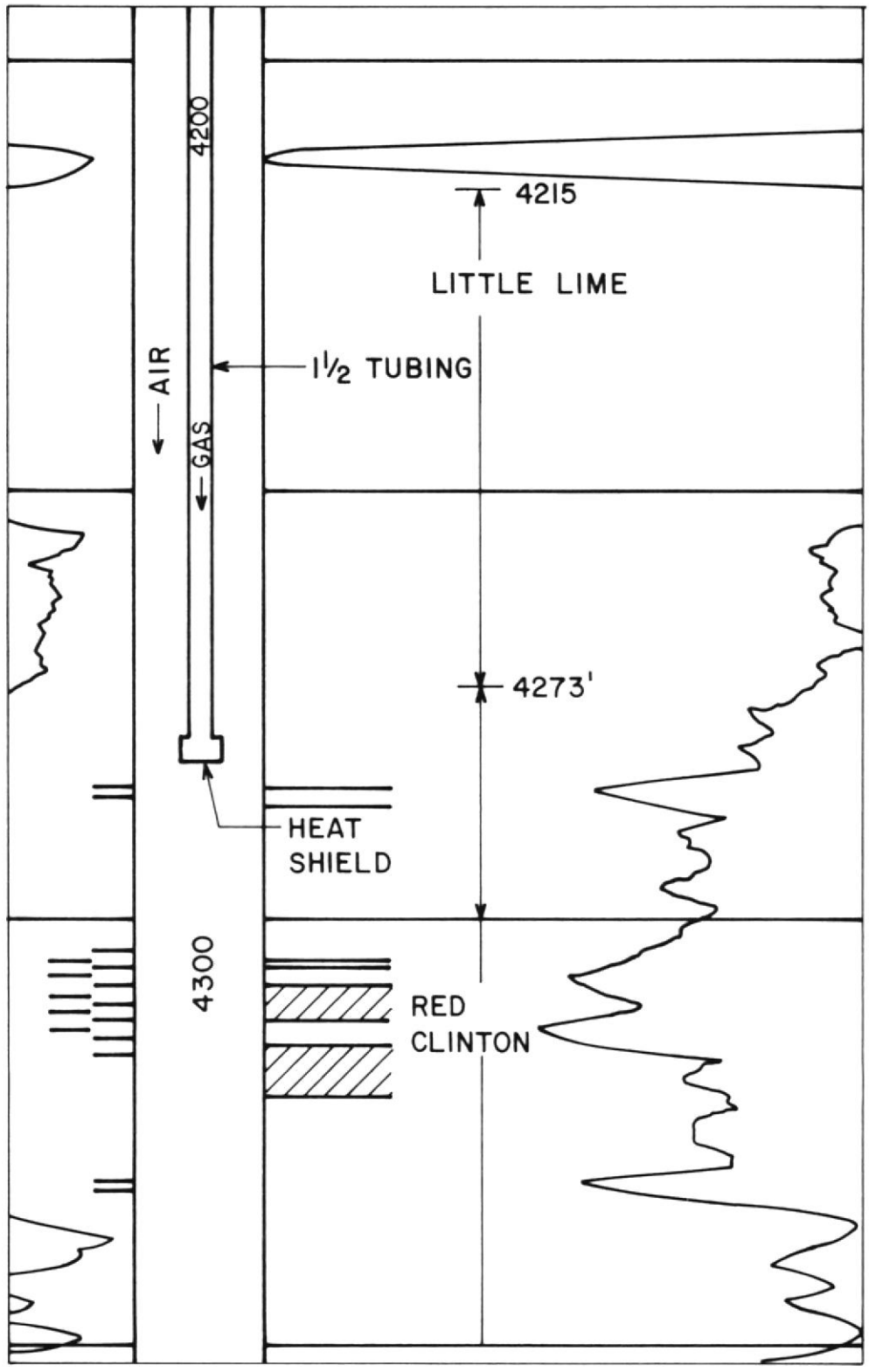


Figure 41. Location of the Heat-shield, Sandy Lake No. 2.

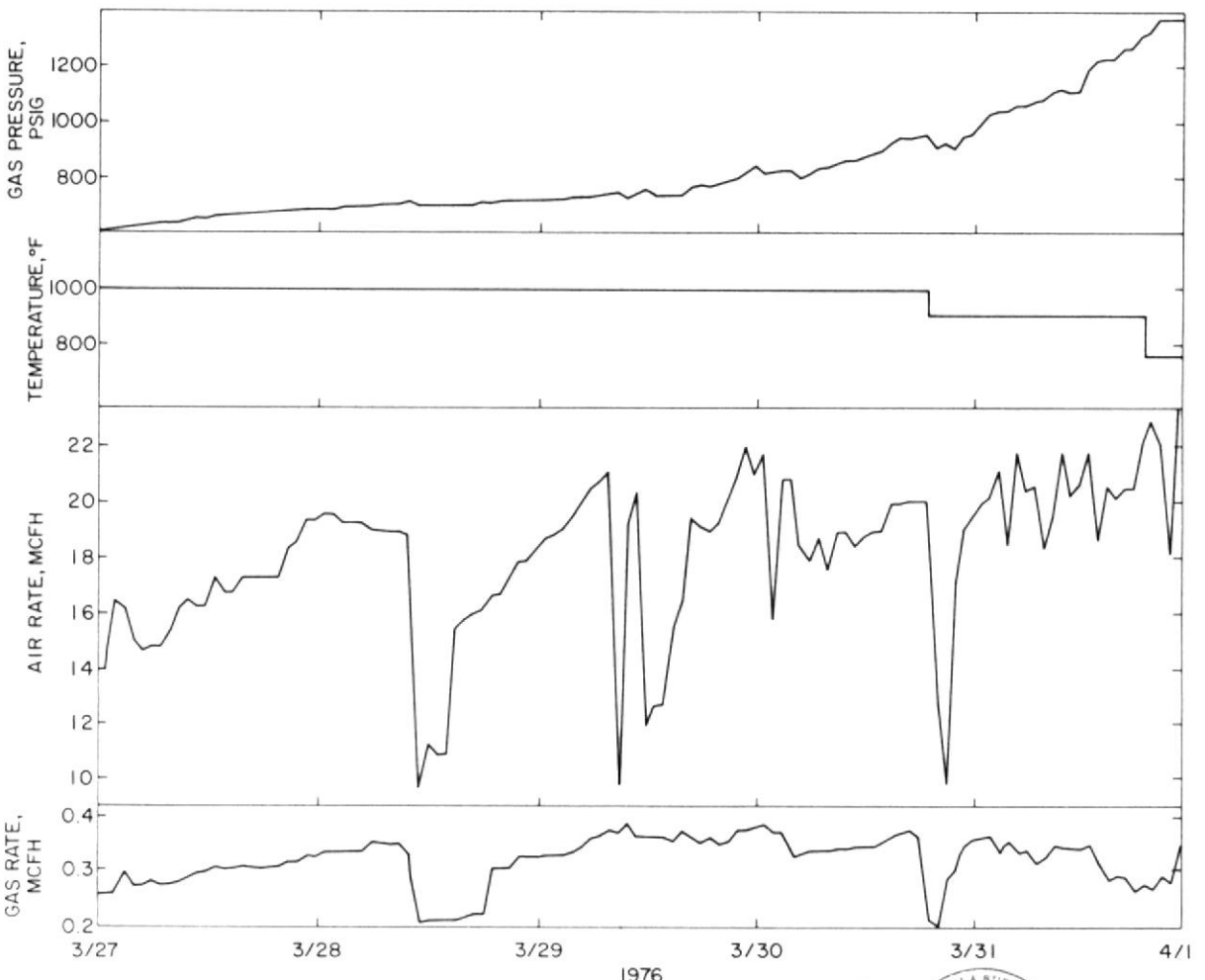


Figure 42. Ignition Data For Sandy Lake No. 2

Total heat injected during the 120-hour burner operation was 10.833 MMBTU. Total gas injection during burner operation was 2175.44 MCF with air continuing to be injected for another 24 hours after termination of burner operation.

Thermal stimulation of East Ohio Gas Tarter No. 1 was initiated on April 3, 1976, after relocation of the air and gas compressors from Sandy Lake No. 2. The air injection line was buried for a short distance close to the compressor skid to reduce the vibrations in the pen movements on the recording meter. A dual choke was also placed in the line to enable the bleeding of air at the compressor and the maintaining of a higher pressure in the line before the choke and meter run. Utilizing these choke valves and maintaining a pressure drop of approximately 100 psi resulted in further reduction of pen fluctuations on the recording meter.

The procedure of ignition for thermal stimulation of this well was identical to that for Sandy Lake No. 2. The location of the heat-shield is shown in Figure 43. Gas injection to displace the tubing prior to ignition was initiated at 11:00 A.M. on April 3, 1976. However, a leak in the gas compressor cooling system caused the gas injection to terminate at 4:00 P.M. for repairs. The leak was repaired and the tubing was displaced with gas on April 4, 1976. Ignition procedures were started on the morning of April 5. A delay was caused when the burner assembly would not clear the valve on the well-head. The East Ohio Gas valve was removed and replaced with a 2-inch full opening gate valve furnished by TOR. Ignition was accomplished at 11:42 on April 5, 1976, after one run with the ignitor tool. Hourly data taken during the gas burner operation are plotted in Figure 44, and show air rate, gas rate and the well-head

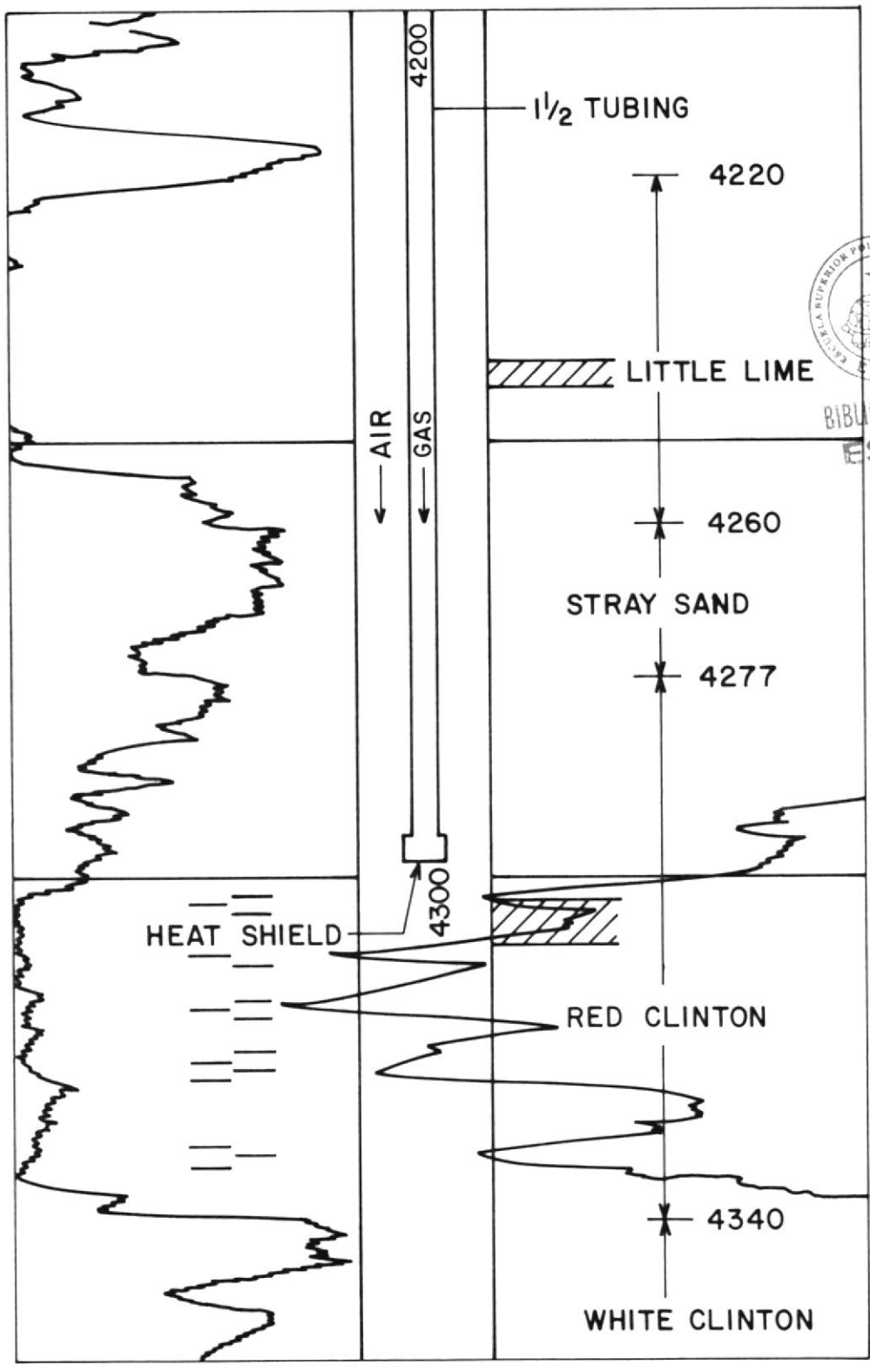


Figure 43. Location of the Heat-shield, Tarter No. 1.

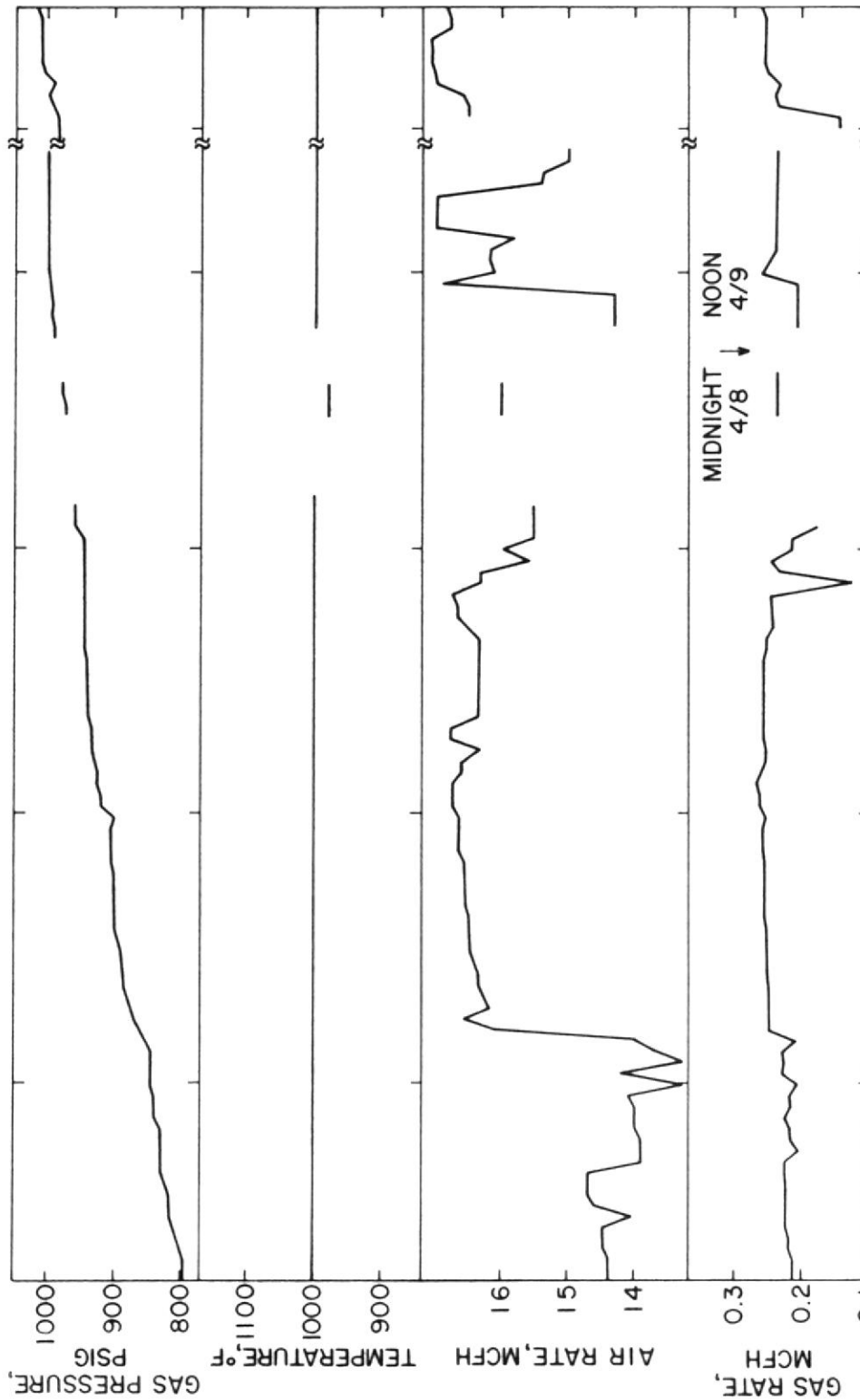


Figure 44. Ignition Data for Tarter No. 1.

gas injection pressure. The average theoretical temperature of the burner calculated from these data is also plotted.

During the first day of operation the air rate was maintained at approximately 350 MCFD. On the morning of April 6, the air rate was raised to approximately 6.4 MCFD and it was increased to 7.2 MCFD on April 6.

Attempts to check burner operation on April 7 were unsatisfactory with two runs apparently not seating in the heat-shield. A second ignition run was made at 3:15 P.M.

Mechanical problems and freezing instrumentation limited burner operations to a few hours on April 8, with a third run of the ingitor tool at 5:50 P.M.

On April 9, a catalytic heater was placed on the gas instrumentation to prevent freezing and the mechanical problems with the gas compressor were repaired. A fourth ignition run was made at 5:47.

On April 10, the nipple on the air compressor discharge safety relief valve broke and both air and gas injection were halted. A sixth ignition run was made at 12:10 P.M. At 1:50 P.M. a run was made with a 36-inch tool containing various pieces of templesticks. The tool was seated in the heat-shield for 15 minutes. One templestick piece remained in the tool upon examination. It was assumed to be one with a 1200°F melting point. At 7:50 P.M. there was a mechanical failure of the engine on the gas compressor, and it was decided to terminate the burner operation at that time.

When burning in Sandy Lake No. 2 was terminated, an analysis of the gas existing the the wellbore was taken, most of the gas was made up of nitrogen (79.15%) and oxygen (20.74), which was expected since right

after burning air was injected for 24 hours. Five days later, purging of Sandy Lake No. 2 was started. Table 23 and Figure 45 show the change in composition with time of the gas purged from Sandy Lake No. 2. The samples withdrawn show a very steady change from mixtures very rich in nitrogen and oxygen to mixtures with high content of methane and after 48 hours of flow the gas analyzed was approaching the original composition of the gas before ignition. When the well was clear of nitrogen and oxygen, testing of Sandy Lake No. 2 started.

Burning of Sandy Lake No. 2 occurred without major complications. This was not the case for Tarter No. 1 where several problems caused the termination of the stimulation. Table 24 shows the data for the analysis of the gas purged from Tarter No. 1.

Testing of this well was not completed and the evaluation of the results obtained was limited to the observation of Sandy Lake No. 2. A comparison of the Modified Isochronal Tests before and after thermal stimulation in Sandy Lake No. 2 is presented in Tables 25 and 26 and Figure 46.

Even though the Isochronal Test plotted does not show any improvement after the stimulation it must be pointed out that the stabilized point after stimulation (.098 MMFCD and 387125 psi^2) was read 48 hours after flowing. The stabilized point before stimulation (.148 MMFCD and 164777.3) was taken only 18 hours of flow. In both cases the flow rate was fluctuating which, unfortunately, makes the test interpretation open to question.

Table 27 and Figure 47 and Table 28 and Figure 48 show the pressure build-up data and plot before and after the stimulation respectively. Table 29 presents the calculation of permeability from these two curves,

TABLE 23

Analysis of Gas Purged from Sandy Lake No. 2 After Ignition

Date	Time		Oxygen %	Nitrogen %	Methane %	Ethane %	CO_2 %	Propane %
3- 4-76	-	a	0.08	2.73	89.72	-	0.0	-
4- 5-76	-	b	1.77	8.38	82.66	4.90	0.0	1.41
4- 5-76	10:05 a.m.	c	20.74	79.15	0.06	0.00	0.05	Trace
4-19-76	1:30 p.m.		7.33	45.60	42.30	2.12	1.44	0.65
4-19-76	2:30 p.m.		8.10	48.38	38.95	2.02	1.50	0.61
4-19-76	3:30 p.m.		8.56	49.68	37.19	1.93	1.55	0.61
4-19-76	4:30 p.m.		8.88	50.27	36.40	1.89	1.53	0.59
4-20-76	9:15 a.m.		8.94	51.90	34.96	1.81	1.44	0.56
4-20-76	12:45 p.m.		9.42	53.21	33.14	1.73	1.51	0.55
4-21-76	10:00 a.m.		8.90	53.44	33.88	1.60	1.16	0.57
4-22-76	9:00 a.m.		8.81	51.57	35.53	1.93	1.13	0.59
4-22-76	1:00 p.m.		8.79	50.46	36.47	1.92	1.31	0.60
4-23-76	9:30 a.m.		8.50	47.94	39.19	2.06	1.23	0.63
4-23-76	2:00 p.m.		8.34	48.35	38.84	2.23	1.20	0.62
4-24-76	9:30 a.m.		8.21	47.15	40.31	2.08	1.20	0.64
4-24-76	4:30 p.m.		8.10	46.32	41.22	2.15	1.12	0.65
4-26-76	9:00 a.m.		7.29	53.52	45.73	2.30	1.03	0.68
4-26-76	4:30 p.m.		7.06	42.04	45.44	2.90	1.14	0.88
4-27-76	9:30 a.m.		6.32	38.89	50.20	2.54	0.82	0.72
4-27-76	4:30 p.m.		6.41	39.21	49.86	2.48	0.77	0.74
4-28-76	9:30 a.m.		6.03	36.02	53.33	2.68	0.73	0.78
4-29-76	6:45 a.m.		5.16	35.77	54.88	2.65	0.45	0.72
4-30-76	6:45 a.m.		4.77	32.67	58.00	2.90	0.43	0.81
5- 3-76	6:45 a.m.		3.30	30.39	61.75	3.10	0.20	0.84
5- 4-76	6:45 a.m.		4.18	30.16	61.01	3.06	0.36	0.83
5- 5-76	6:45 a.m.		3.31	25.85	66.03	3.22	0.33	0.86
5- 7-76	6:45 a.m.		2.59	20.83	72.27	3.13	0.23	0.70
5-10-76	6:45 a.m.		1.71	19.85	73.57	3.42	0.12	0.87
5-12-76	6:45 a.m.		2.04	19.69	73.53	3.48	0.16	0.82
5-13-76	9:00 a.m.		2.00	16.28	76.31	3.80	0.37	0.93
5-14-76	6:45 a.m.		1.91	16.94	76.37	3.52	0.22	0.77
5-18-76	9:15 a.m.		1.09	13.98	78.88	4.19	0.13	1.12

a. Composition before Ignition

b. Composition in Tubing before Purging

c. Composition in Casing before Purging

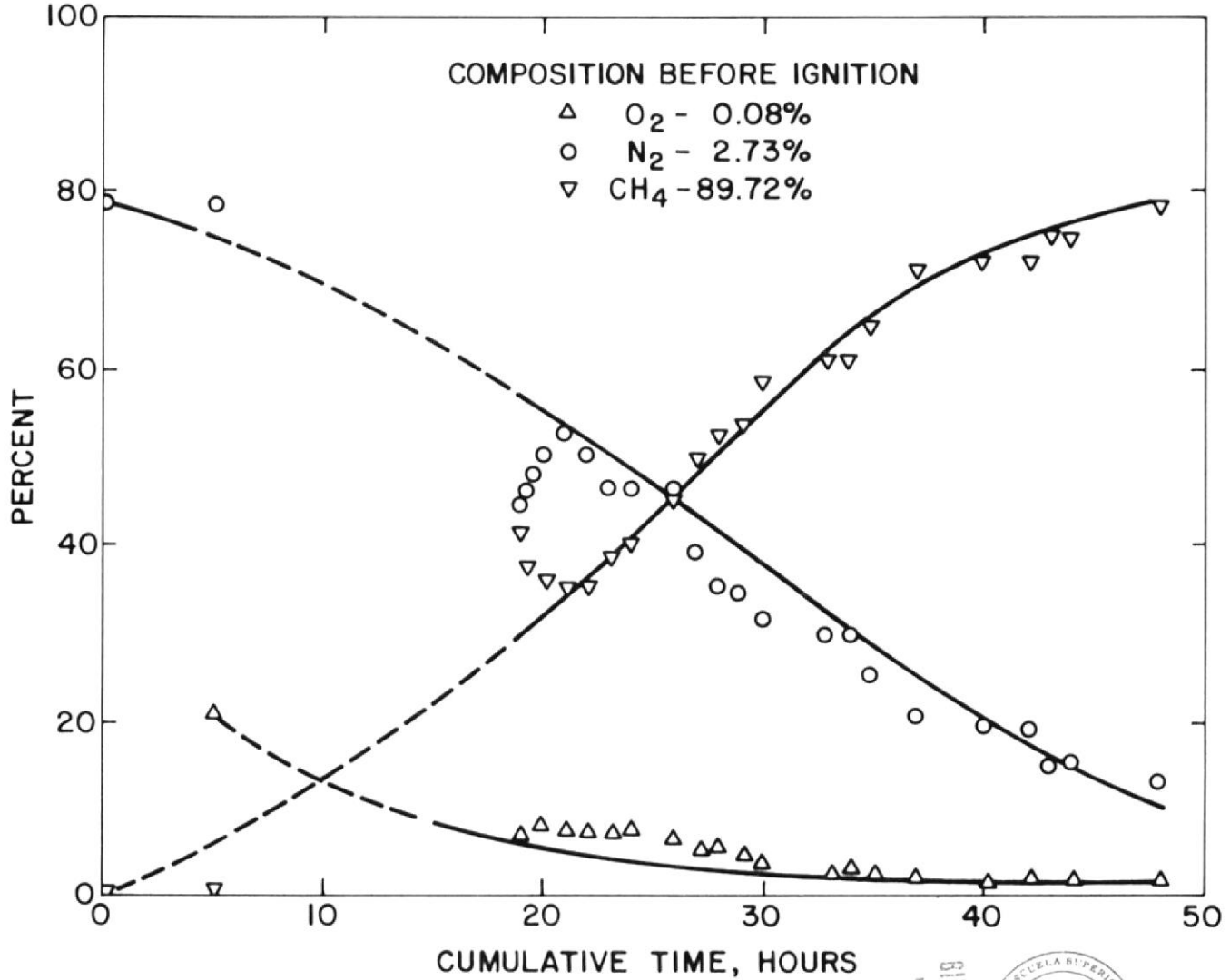


Figure 45. Composition of Gas Purged from Sandy Lake No.

TABLE 24

Analysis of Gas Purged from Tarter No. 1 After Ignition

Date	Time		Oxygen %	Nitrogen %	Methane %	Ethane %	CO_2 %	Propane %
-	-	a	NA	NA	NA	NA	NA	NA
4-14-76	10:00 a.m.	b	Trace	2.35	89.96	5.32	0.0	1.46
4-14-76	10:30 a.m.	c	Trace	0.89	93.86	3.34	1.0	0.55
4-20-76	9:30 a.m.		17.12	73.02	8.41	0.54	0.54	0.20
4-21-76	9:00 a.m.		14.66	64.45	18.48	1.04	0.76	0.34
4-22-76	1:30 p.m.		16.33	70.04	11.52	0.73	0.85	0.27
4-23-76	9:00 a.m.		16.40	69.52	12.06	0.77	0.81	0.28
4-24-76	10:00 a.m.		14.33	64.10	18.89	1.12	0.87	0.40
4-26-76	9:30 a.m.		11.50	54.0	31.10	1.64	0.88	0.55
4-27-76	9:00 a.m.		12.56	57.43	27.0	1.41	0.78	0.48
4-28-76	9:00 a.m.		12.29	55.75	28.78	1.56	0.74	0.53
4-29-76	7:00 a.m.		15.05	65.80	17.27	0.92	0.55	0.30
4-30-76	7:00 a.m.		16.89	64.23	17.28	0.83	0.42	0.25
5- 3-76	7:00 a.m.		13.44	59.48	25.06	1.05	0.52	0.28
5- 4-76	7:00 a.m.		10.76	54.25	31.74	1.76	0.61	0.59
5- 5-76	7:00 a.m.		11.28	58.36	27.59	1.50	0.52	0.50
5- 7-76	7:00 a.m.		15.26	66.38	16.64	0.85	0.42	0.25
5-10-76	7:00 a.m.		12.70	57.42	27.57	1.33	0.42	0.36
5-12-76	7:00 a.m.		10.60	50.38	35.61	1.93	0.48	0.64
5-13-76	9:30 a.m.		10.05	47.30	38.97	2.13	0.45	0.70
5-14-76	7:00 a.m.		10.36	50.10	36.38	1.88	0.43	0.57
5-18-76	8:45 a.m.		8.53	43.0	44.27	2.47	0.43	0.83

TABLE 25

Modified Isochronal Tests Before and After Stimulation, Sandy Lake No. 2

BEFORE						AFTER					
Well is	Time	W.H. Press. (psig)	BHP (psig)	Flow Rate MCFD	Temp. °F	Well is	Time	W.H. Press. (psig)	BHP (psig)	Flow Rate MCFD	Temp °F
Open	10:55 a.m.	500.		68	62	Open[2]	10:00 a.m.	550.	620		
	11:05	500.		70	62		10:15	350.	410	579	56
	11:15	500.		69	58		10:30	280.	300	635	56
	11:25	500.		67	57		10:45	200.	255	536	56
	11:50	500.		69	56		11:00	145.	200	519	56
	11:55	500.	566.17	0.0		Shut in	11:00				
Shut in	11:55	500.	566.17	68.6[1]			11:15	420.	485		
Open	12:55 p.m.	500.		92.0	95		11:30	480.	535		
	1:05	500.		92.0	60		11:45	520.	580		
	1:15	500.		92.6	57		12:00	530	590		
	1:25	500.		93.0	57	Open	12:00	530	590	325	56
	1:55	495.	563.72	87.0	56		12:15 p.m.	450	520	310	56
Shut in	1:55	500.	566.50	91.32[1]			12:30	420	485	310	56
Open	2:55	500			87		12:45	400	464	317	56
	3:05	490		260.0	87		1:00	390	455	310	56
	3:15	480		218.0	54	Shut in	1:00				
	3:25	470		300.0	54		2:00	520	580		
	3:35	470		261.0	53	Open	2:00	520	580	163	64
	3:55	460	524.88	266.0	53		2:15	500	570	133	59
Shut in	3:55	500	567.03	261.8[1]	53		2:30	470	540	183	58
Open	* 9:35 a.m.	500	567.03		78		2:45	470	540	183	58
	9:50	490		200.0	52		3:00	460	530	183	58
	10:35	470	536.11	210.0	52	Shut in	3:00				
	11:35	450		208.0	53	Open	10:00 a.m.	580	645	631	
	3:55 p.m.	380		257.0	52		10:15	350	410		53
	** 9:55	345	396.80	148.0	52		11:00	130	190	460	53
							12:00	130	190	390	55
							12:15	120	170		55
							1:00	120	170	300	56
							[3]10:00	120	170	96	56
							2:00	120	170	120	56

*This time corresponds to the next day
**Stabilized point, 18 hours later

1. These values are average
2. Well was shut in 6 days
3. This value was read 2 days later.

TABLE 26

Modified Isochronal Tests Before and After Stimulation,
Sandy Lake No. 2, Plotted Values

BEFORE				AFTER			
Average Flow Rate Q (MMSCF/D)	P_e Psi	P_q Psi	$P_e^2 - P_q^2$ Psi^2	Average Flow Rate Q (MMSCF/D)	P_e Psi	P_q Psi	$P_e^2 - P_q^2$ Psi^2
0.0686	566.17	566.17	0.0	.519	620	200	344440.0
0.09132	566.5	563.72	3142.01	.310	490	455	141075.0
0.2618	567.03	524.88	46024.0	.183	580	530	55000.0
0.2100	567.65	536.11	34812.6	.096	[1]645	170	387.125
*0.1480	567.65	396.8	164777.3	**.120	645	170	387.125

SG: 0.6
Depth: 4420 feet
Tc: 360°F
Pc: 670 psia

*stabilized point, after 18 hrs.
**point read after 18 hrs.
[1]stabilized point after 48 hrs.

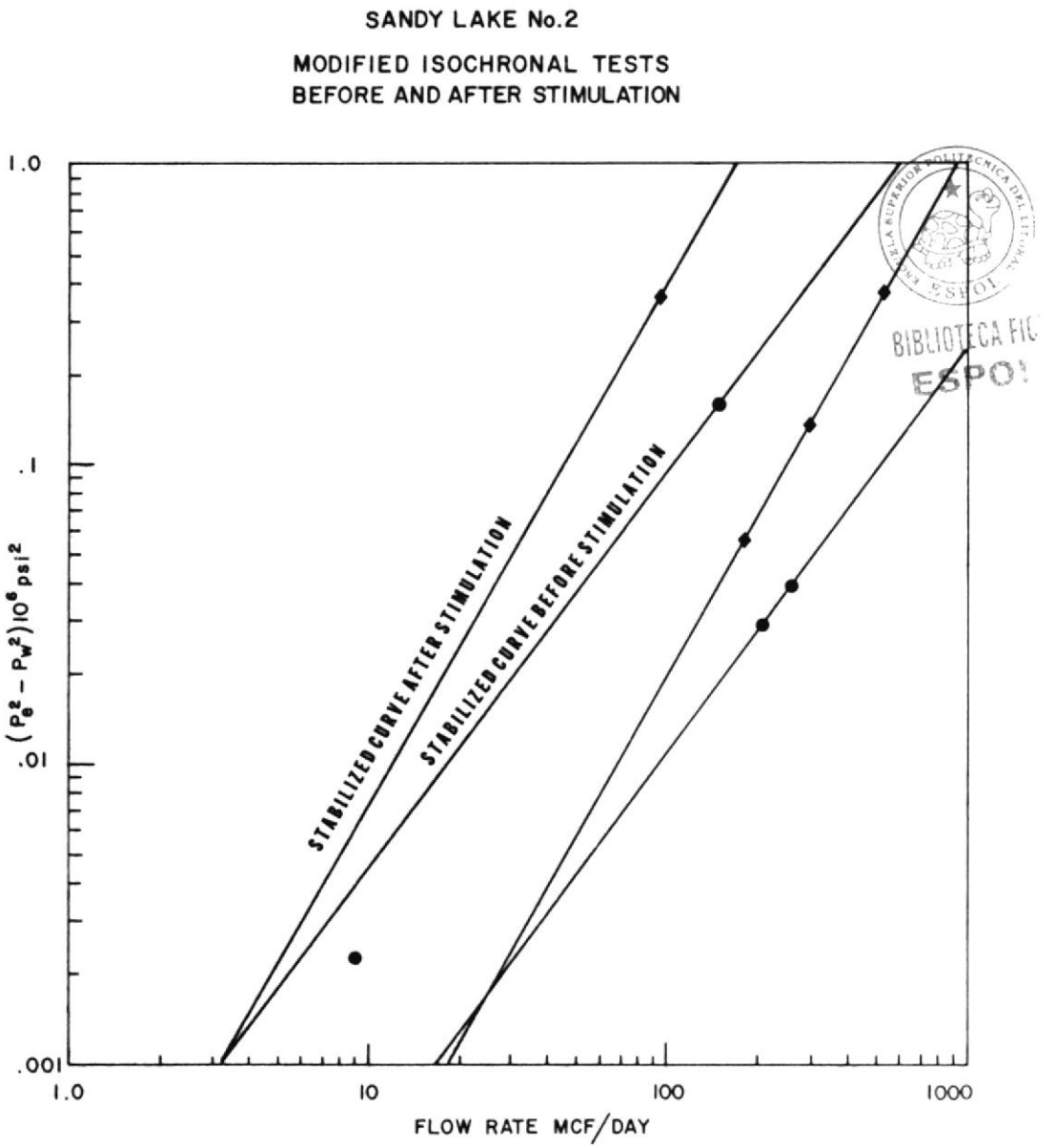


Figure 46. Comparison of Modified Isochronal Tests, Before and After Stimulation

TABLE 27

Sandy Lake No. 2 Pressure Build-up Data, Before Stimulation

t_h = 17.5 hours

Q_{avg} = 200 MCFD

	Time (hours)	Wh.Pressure (PSIG)	SBHP (PSIG)	Wh.Temperature (°F)	$\frac{t+\Delta t}{\Delta t}$
10:00	0	340	391.14	54	-
12:30	2.5	345	396.55	57	8.2
1:00	3	375	407.41	62	6.83
2:00	4	375	429.26	69	5.37
3:00	5	390	445.91	69	4.5
6:00	8	400	457.07	68	3.19
12:00	14	419	478.75	67	2.25
6:00	20	425	484.86	65	1.88
12:00	26	439	500.00	75	1.67
6:00	32	440	500.87	79	1.55
12:00	38	450	412.87	65	1.46
6:00	44	459	423.24	60	1.40
12:00	50	465	427.61	96	1.35
6:00	56	470	533.83	85	1.31
12:00	62	470	535.15	65	1.28
6:00	68	479	545.62	59	1.26

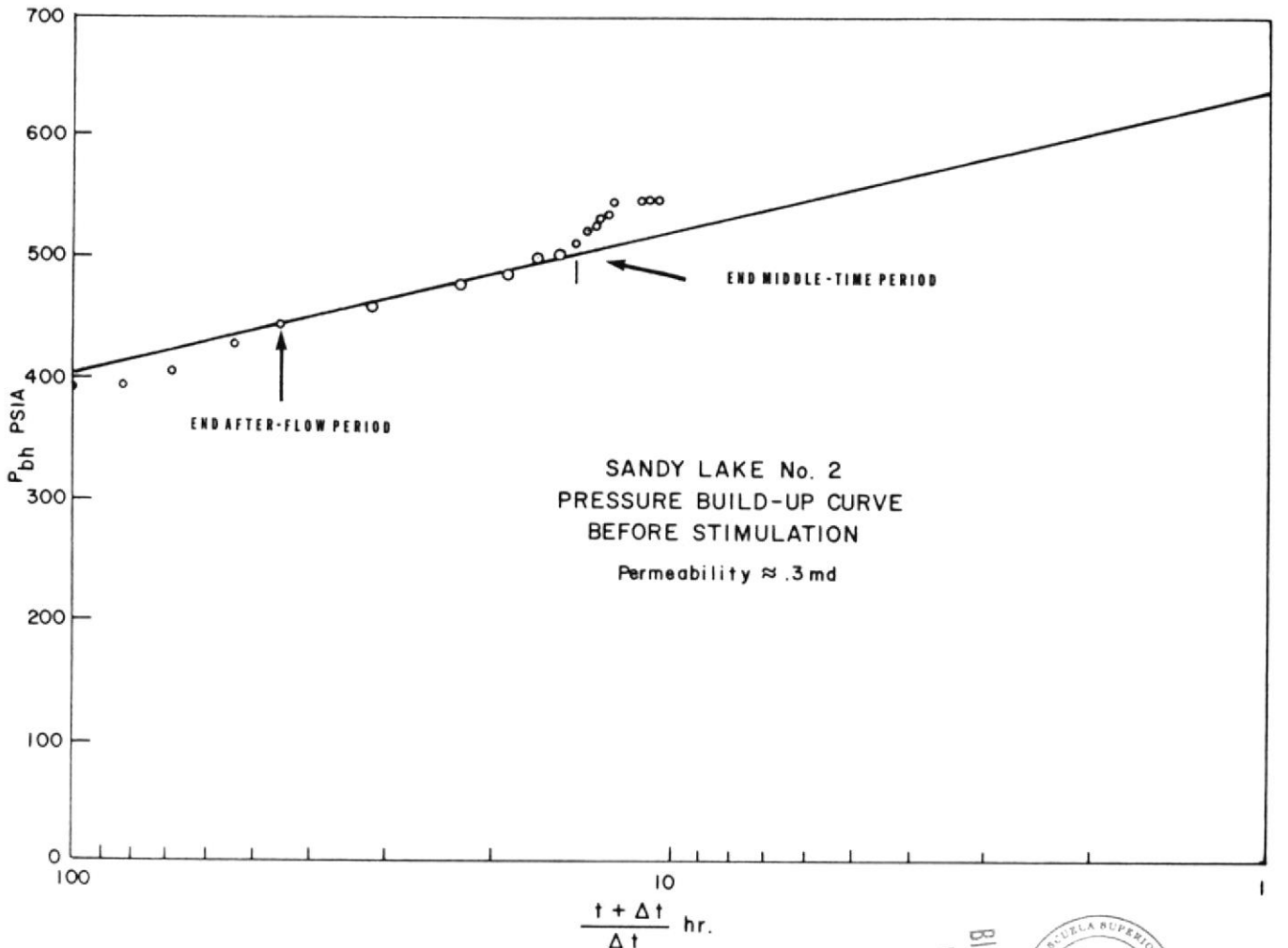


Figure 47. Pressure Buildup Curve Before Stimulation

TABLE 28

Sandy Lake No. 2, Pressure Build-up Data, After Stimulation

th = 68.6

Q_{avg} = 237.25 MCFD

Time (hours)	Wh.Pressure (PSIG)	SBHP (PSIG)	Wh.Temperature (°F)	$\frac{t+\Delta t}{\Delta t}$
9:00 a.m. 0.00	340.0	375.0	54.0	∞
0.25	360.0	400.0	57.0	275.0
0.50	400.0	445.0	62.0	138.0
0.75	410.0	455.0	69.0	92.0
1.00	420.0	465.0	69.0	67.0
1.25	430.0	475.0	68.0	56.0
1.50	440.0	485.0	67.0	47.0
1.75	445.0	490.0	65.0	40.0
2.00	450.0	500.0	75.0	35.0
2.25	455.0	510.0	79.0	31.0
2.50	457.0	512.0	80.0	28.0
2.75	458.0	513.0	80.0	26.0
3.00	460.0	515.0	85.0	24.0
4.00	480.0	535.0	85.0	18.0
8.00	500.0	555.0	80.0	9.6
12.00	505.0	560.0	70.0	6.7
16.00	510.0	565.0	60.0	5.3
20.00	520.0	575.0	60.0	4.4
24.00	525.0	580.0	65.0	3.8
28.00	530.0	585.0	70.0	3.4
32.00	540.0	595.0	70.0	3.1
36.00	540.0	595.0	75.0	2.9
40.00	540.0	595.0	70.0	2.7
44.00	540.0	595.0	65.0	2.6
48.00	550.0	605.0	65.0	2.4
52.00	560.0	615.0	65.0	2.3
56.00	560.0	615.0	70.0	2.2
60.00	560.0	615.0	60.0	2.14
64.00	560.0	615.0	55.0	2.07
68.00	570.0	625.0	60.0	2.0
72.00	580.0	635.0	65.0	1.9

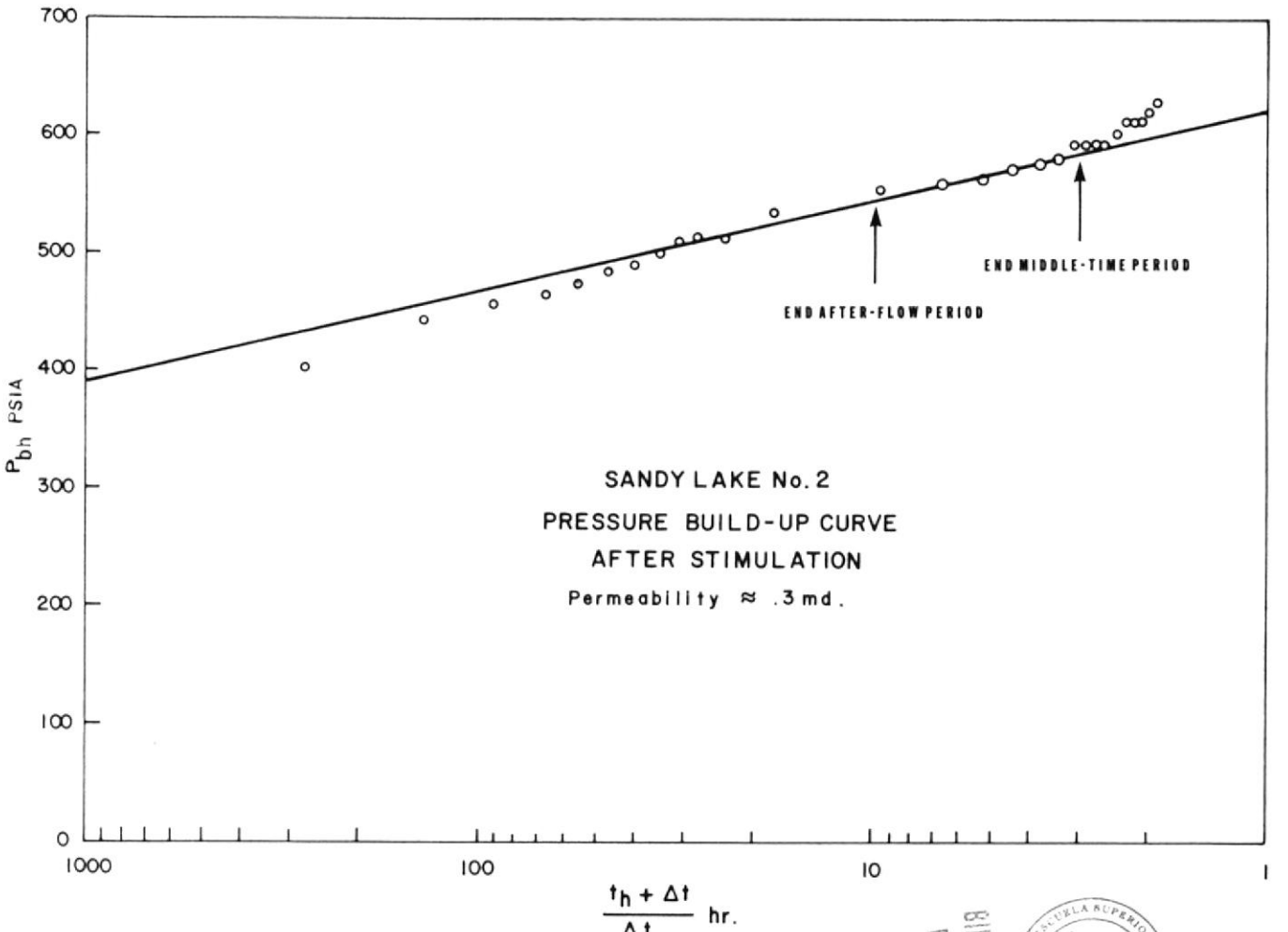


Figure 48. Pressure Buildup Curve After Stimulation

TABLE 29

Sandy Lake No. 2, Calculation of K (md)

$$K = 162.6 \frac{q_g \mu_g B_g}{m h}$$

μ = Gas Viscosity , cp

q_g = Stabilized Daily Gas Production, bbl/day

m = Slope of the Buildup Stabilized Curve, psi/cycle

h = Formation thickness, feet

B_g = Gas formation Factor given by :

$$B_g = 0.02829 \frac{Z\ T}{P}$$

where

Z = Compressibility Factor

T = Temperature , ^{o}R

P = Pressure, psi

	q_g	S.G.	T_c	P_c	T	P	P_r
Before Stimulation :	26360.0	0.6	360.	670.	538.	567.	1.50
After Stimulation :	(21373.2) 17098.0	0.63	367.	670.	565.	640.	1.53

	P_r	Z	B_g	μ_g	m	h
Before Stimulation :	0.84	0.92	0.0247	0.0134	116	40.
After Stimulation :	0.95	0.92	0.0230	0.0134	80	40

	K
Before Stimulation :	0.305
After Stimulation :	(0.33471)/0.26776

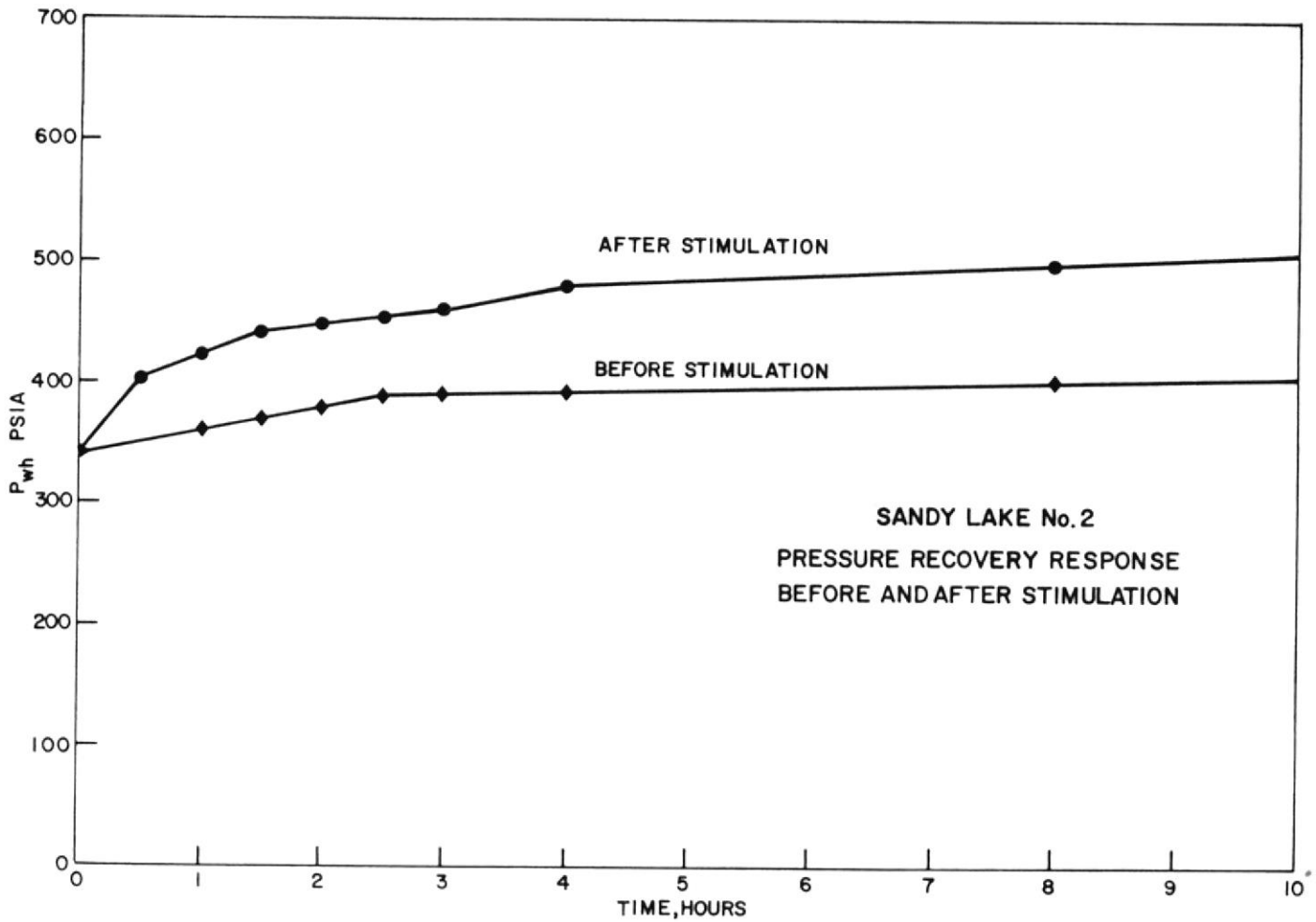


Figure 49. Pressure Recovery Response Before and After Stimulation

the values obtained are approximately equal with a slight improvement after stimulation.

The pressure buildup curves before and after stimulation show essentially the same average formation permeability which is to be expected. This is the permeability out away from the wellbore. It was hoped that a change in the after flow portion of the curves would reveal the effect of the stimulation. This was not readily apparent. Two other indications had to be used.

It can be seen that after the stimulation, the well builds up pressure faster than before the thermal stimulation which indicates a cleaned up wellbore and fracture system. This increase was observed in all the points of the tests. Figure 49 shows the increase in pressure recovery response after stimulation as compared to the response before stimulation.

A McKinley (19) type curve analysis was made for the data from the build up curves before and after stimulation from this study. It can be seen that there was nearly a four-fold increase in the wellbore transmissibility as reported in Figure 50 and Table 30. This improvement is the best evidence that the wellbore and fracture system was partially cleaned up by the thermal stimulation method. In Table 31, average values for the production data before stimulation (36 MCF/D) as compared to production data after the stimulation (average of 57 MCF/D for the first month) show that the thermal stimulation of Sandy Lake No. 2 had some degree of success. Unfortunately, because of the extremely low permeability of the Clinton sand in this area (under 1 md) and because of the low pressure of the formation, the results obtained are not as good as was expected at the start. The productivity increase does not seem to be permanent.

TABLE 30

Data for the McKinley Type Curve Analysis

AFTER STIMULATION				BEFORE STIMULATION			
Δt min.	Δp psi	Δt min.	Δp psi	Δt min.	Δp psi	Δt min.	Δp psi
0	0.	135	135.	0	0.	135	46.
15	25.	150	137.	15	5.	150	48.
30	70.	165	138.	30	10.	165	50.
45	80.	180	140.	45	15.	180	50.
60	90.	240	160.	60	20.	345	60.
75	100.	480	180.	75	25.	460	65.
90	110.	720	185.	90	30.	580	70.
105	115.	960	190.	105	35.	700	79.
120	125.			120	40.	820	80.
						940	82.

Data

μ = .013 cp
h = 40 feet

J/F	3000.0	1000.0	100.0
ΔP	10.0	10.0	10.0
$\Delta PF/q$	1.5^{-2}	10^{-1}	1.2×10^{-1}
q	455.	683.	455.
F	.6825	6.83	5.46
J	2047.	6830.	546.
K	.6653		.1775

TABLE 31

Production Data for Sandy Lake No. 2

Average Production Before Burning		
OIL	WATER	GAS
3.3 BPW	1.5 BPW	36 MCF/D

After Burning (on line 6/8/76)

GAS PRODUCTION

6/8 - 6/12	75 MCF/D
6/15 - 6/22	47 MCF/D
6/22 - 6/29	58 MCF/D
6/29 - 24 hours test	47 MCF/D

AVERAGE WATER AND OIL PRODUCTION

Oil	2.7 BPW
Water	6. BPW

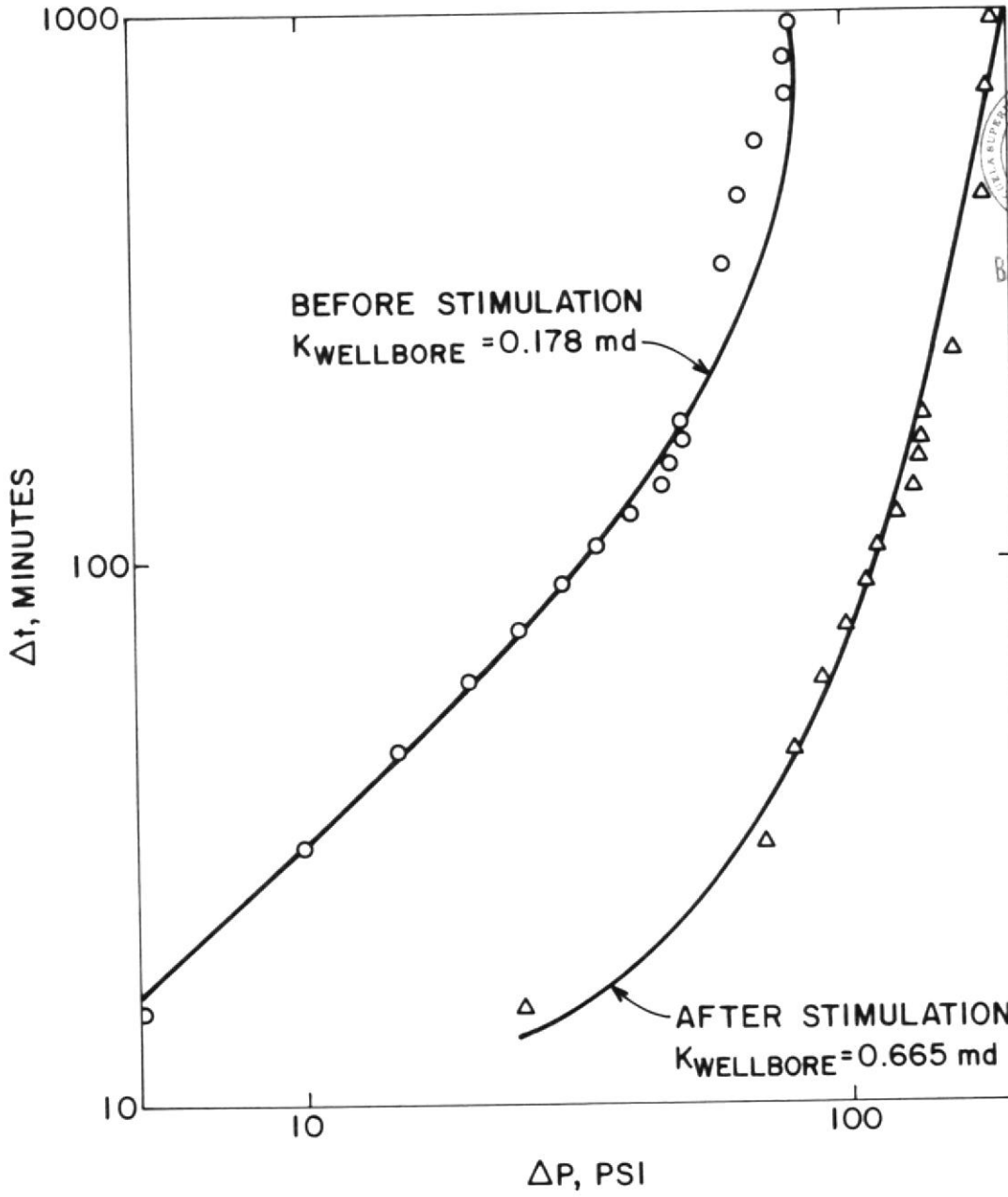


Figure 50. McKinley Type Curve Analysis

VII. SUMMARY AND CONCLUSIONS

The reduction in permeability in several sandstones because of paraffin deposition was studied. Laboratory experiments were conducted in order to evaluate the effect of solvent injection, ultrasonic energy and thermal stimulation in dissolving the paraffin deposits and increasing the existing permeability in the different sandstones studied.

Of these methods, thermal stimulation was judged to be the most attractive for a field sized experiment.

A system of three wells was selected from a gas field in the Clinton Sand of Eastern Ohio for conducting the field experiment.

Two of these wells were thermally stimulated using a down hole gas burner, the other well was used as a control well and to characterize the Clinton Sand in this area. Within the framework of the present study, the principal conclusions of this investigation are summarized as follows.

Laboratory Experiments

1. For all the cases studied, the change in cloud point temperature was in direct proportion to the paraffin concentration, the relation was found to be linear.
2. Even though some of the solvents tried gave large improvements in permeability by dissolving the paraffin plugging, the volumes required made these fluids impractical for field trials.
3. Ultrasonic Energy successfully released the paraffin plugging for all the cases studied. Cavitation and increase in temperature were the principal factors of permeability increase in the plugged cores.

4. In the presence of water,and under the action of ultrasonic energy,oil can form a very stable emulsion within the sandstone.
5. The excessive production of heat around the probe generating ultrasonic energy is a serious limitation to the use of large field sized tools.
6. Thermal stimulation of rocks appears to be the most attractive way to improve permeability in damaged cores. This improvement is due to the melting of the paraffin deposits and to the fracturing of the reservoir rock, as well as to the permanent dehydration of the clays present in water sensitive rocks.

Field Experiment

1. Gas wells can be succesfully stimulated using a down hole burner.
2. The increase in wellbore transmissibility,even though not as large as expected,is a good indication of well stimulation.
3. The thermal stimulation described is a near wellbore stimulation. From the analysis of the pressure buildup tests and isochronal tests conducted before and after the stimulation it ca be said that the rock matrix did not exhibit any degree of permeability improvement.
4. No further paraffin plugging is to be expected in the wells after thermal stimulation,since large drops in temperature and pressure which originally caused the paraffin to precipitate no longer exist.
5. Unexpected problems encountered in back-flowing the products of combustion and air from the well indicate that smaller,more controlled stimulation should be studied.

6. The equipment used in the stimulation for gas injection was not reliable. Other burner systems should be investigated.

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APPENDIX A

CONTROL WELL SPECIFICATIONS AND WELL TESTING PROCEDURES

packed in plastic bags and boxes and shipped to Oil Field Research in Waldo, Ohio for whole core analysis.

(iii) Core Analysis

A. Each sample was analysed for porosity, absolute permeability (vertical, horizontal, and horizontal 90°) and oil and water saturations.

B. Core Lab's main office in Evansville, Indiana determined the relative permeability and capillary pressure relationships between the gas, oil and water saturations of special core samples.

C. Intermediate sections of core were reserved for use in lab studies at The Pennsylvania State University.

(iv) Logging

A. When total depth was reached the wellbore was conditioned and the following electric logs were run by Schlumberger: Gamma Ray - density - caliper (primary log O-TD), side wall neutron, sonic, ampliture sonic, dual induction laterolog, and synergetic computer processed interpretation.

B. To help determine rock properties a 3-D sonic log was run by Birdwell.

C. Birdwell's 3-D sonic log was also used to determine cement bonding before and after fracturing and to obtain rock properties across open hole section after fracturing.

D. A radioactive tracer log was run after fracturing by Birdwell to record radioactive material injected during thermal treatment for determining fluid displacement.

I. A fresh water slurry with additives of Barafloc and lime was used as a drilling fluid to the coring point.

J. Prior to reaching the coring point a low fluid loss salt base mud possessing the following constituents and properties was added to the drilling fluid:

Mud Constituents: Zeogel, Auper vis bestos, Dextrid, caustic soda and Q-Broxin.

Mud Properties: Weight 10.0 $\pm$ lb/gal; viscosity 32-34 sc. Marsh, water loss 1-5 cc.

K. When the coring point was reached, the condition of the drilling mud was checked. The well bore was then circulated to condition the well in preparation for coring.

L. All drilling muds and field engineering was supplied by Baroid.

M. A Baroid gas detector was put into operation from the base of the surface casing to the total depth.

(ii) Coring

A. Coring was performed by Christensen and core orientation by Eastman.

B. The well was cored with a full gauge 7 7/8 inch diamond core bit.

C. Coring began at a point above the Clinton Sand as determined from sample evaluation.

D. A four-inch oriented core was taken of the entire Clinton Sand section which represented a 120-foot section comprised of siltstones, sandstones and shales of the Thorold (Stray Clinton) and sandstones and shales of the Grimsby (red and white Clinton).

E. The recovered core was visually inspected and described by the exploration and development geologist. The complete core was

The purpose of this appendix is to give the control well specifications as well as the procedures followed in the testing of the well system.

Control Well Specifications

(i) Drilling

A. The well was drilled with fluid type rotary drilling rig.

B. Approximately 100 ft. of 11 3/4 inch OD conductor pipe was cemented in place.

C. An 11-inch surface hole was drilled with aquagel (Bentonite) slurry with additives of soda ash and Ben-Ex.

D. Approximately 550 feet of 8 5/8 inch OD surface casing, K-55, 24 pounds per foot, was run and cemented on the surface with approximately 250 sacks of Class A Surface Pozmix with two percent calcium chloride.

E. A 7 7/8 inch hole was drilled out from under the surface casing to the coring point selected by exploration and drilling geologists.

F. When coring was completed a 7 7/8 inch hole was drilled approximately fifty feet below the Clinton Sand into but not through the Whirlpool Sandstone to create sufficient hole for logging and setting of formation debris and frac sand.

G. Formation samples were caught at ten (10) foot intervals from the base of the conductor pipe to the base of the Big Lime to the coring point.

H. A double screen shale shaker was used to help keep cuttings from being circulated with the drilling fluid. Steel mud tanks were also used.

E. A bottom hole temperature was taken by both Schlumberger and Birdwell during the initial logging.

(v) Completion

A. New API 4 1/2 inch OD, K-55, 10 1/2 pound per foot casing was run and set on a Hallibruton full-flow packer shoe. Casing centralizers were run on every third joint of the 4 1/2 inch casing to the top of Big Lime formation.

B. The packer was settled above the Clinton Sand at a point determined from log evaluation.

C. Circulation was established between the 4 1/2 inch casing and the wellbore prior to cementing.

D. The 4 1/2 inch casing was cemented by Halliburton with approximately 275 sacks (equivalent to 1,000 feet of fill up) of class A cement.

E. During the final stage of cementing the interval components of the packer were discharged out the bottom of the shoe. In the open hole below the Clinton sand, thus no plugs, valves or seats remain in the casing to be drilled out.

F. After the drilling contractor moved off the location, a four-inch gate valve was installed on the well.

G. An East Ohio service machine was positioned over the well to swab and bail the well in preparation for testing.

(vi) Well Head and Production Equipment

A. A standard East Ohio well head and production equipment was installed prior to testing procedures.

B. Flow rates were determined by orifice measurement equipment consisting of a four-inch orifice run and an American Mercury Meter.

Well Test Procedures

A. After the well was cleaned up it was shut in to complete construction of the well head and production facilities.

B. During the shut-in period after the well head was installed, the bottom hole reservoir pressure and the pressure on the well head were recorded.

C. The well was shut in long enough to reach a stable, built-up condition.

D. When the stable pressure condition was reached, the well was turned into the line.

E. It was flowed at various rates for several days to find a rate that could be sustained while keeping the well clear of fluids.

F. The series of tests proceded as follows:

(i) The well was shut in long enough to reach a stable built-up condition.

(ii) (1 day) Isochronal tests were started to determine the slope of the back pressure curve. The well was run at three different rates for flow periods of 1 hour, alternating with one hour shut in periods between rates. The well was shut in until next day.

(iii) (5 days) A pressure drawdown test was started for drawdown analysis and stabilized point of back pressure test.

(iv) (10-14 days) A pressure buildup test was begun. Well was shut in. Dead weight test was recorded every 10 minutes for the first two hours.

(v) When the natural testing was completed, the well was stimulated and the above testing procedures were repeated.

APPENDIX B

CORE ANALYSIS STUDIES

Whole Core Analysis

Table 32 and Figures 51 to 54 show an estimated formation top prognosis to aid in picking the coring point for the Clinton formation in the Sandy Lake No. 3 test well. The clinton formation was diamond cored in the interval 4225.0-4341.0 feet. The core diameter was four inches, and the equipment cut an oriented core with scribe marks along its circumference in a vertical direction. The interval 4275-4336.9 feet was sampled and analyzed by Oil Field Research Inc.

Table 33 presents the results of the core analysis. The analyzed sections may be divided in two parts based upon difference in saturation values. The lower portion of the section, 4276.6-4339.9 feet contains 27.9 feet of oil bearing sandstone. The average of the parameters tested is presented in Table 34.

It was not possible to utilize whole core techniques to determine the horizontal or vertical permeability. These tests were conducted by cutting 3/4 inch diameter plugs from the sample represented. The reason for this change in technique was the scribe marks of the oriented core were cut too deeply into the core for the technician to seal the mark from air movement. Although it may be concluded the permeability data is less than desirable, it is suggested that the plug permeabilities are representative of the matrix rock and any additional permeability is available only in vertical fractures, joints, or bedding planes, all of which may or may not be of limited influence on the performance of the reservoir. Table 35 gives a description of the formation cored and Table 36 shows the interval which presented hydrocarbons.

TABLE 32

Clinton Reservoir Study - Control Well

EOG - SANDY LAKE LAND CO. COMM. #3
Lot 44, Rootstown Twp., Portage Co.
GL(Top) = 1100' Est. KB = 1100'

Formation	Subsea	Estimated Depth
Berea	+ 780	330'
Big Lime	-1260	2370'
Oriskany	-1540	2650'
Selt	-1920	3030'
Lockport	-2680	3790'
Newburg	-2730	3840'
Top Packer Shell	-3050	4160'
Base Packer Shell	-3105	4215'
Red Clinton	-3145	4255'
White Clinton	-3205	4315'
Base White Clinton	-3235	4345'
Whirlpool SS	-3285	4395'
T.D.	-3280	4390'

Estimate start coring 5-10' below base packer shell and core approximately 130' to below base White Clinton.

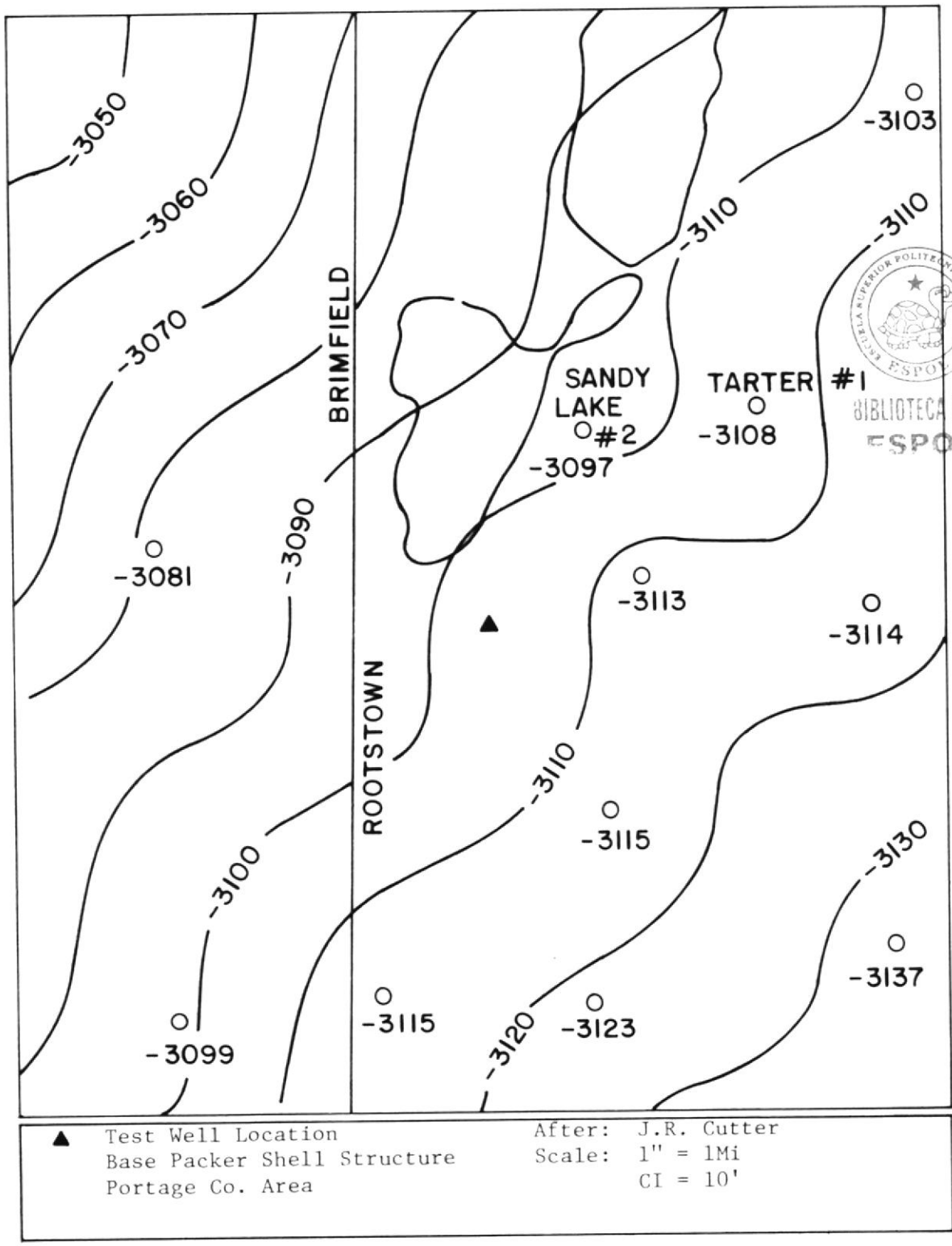


Figure 51. Clinton Reservoir Study Control Well Base Packer Shell Structure

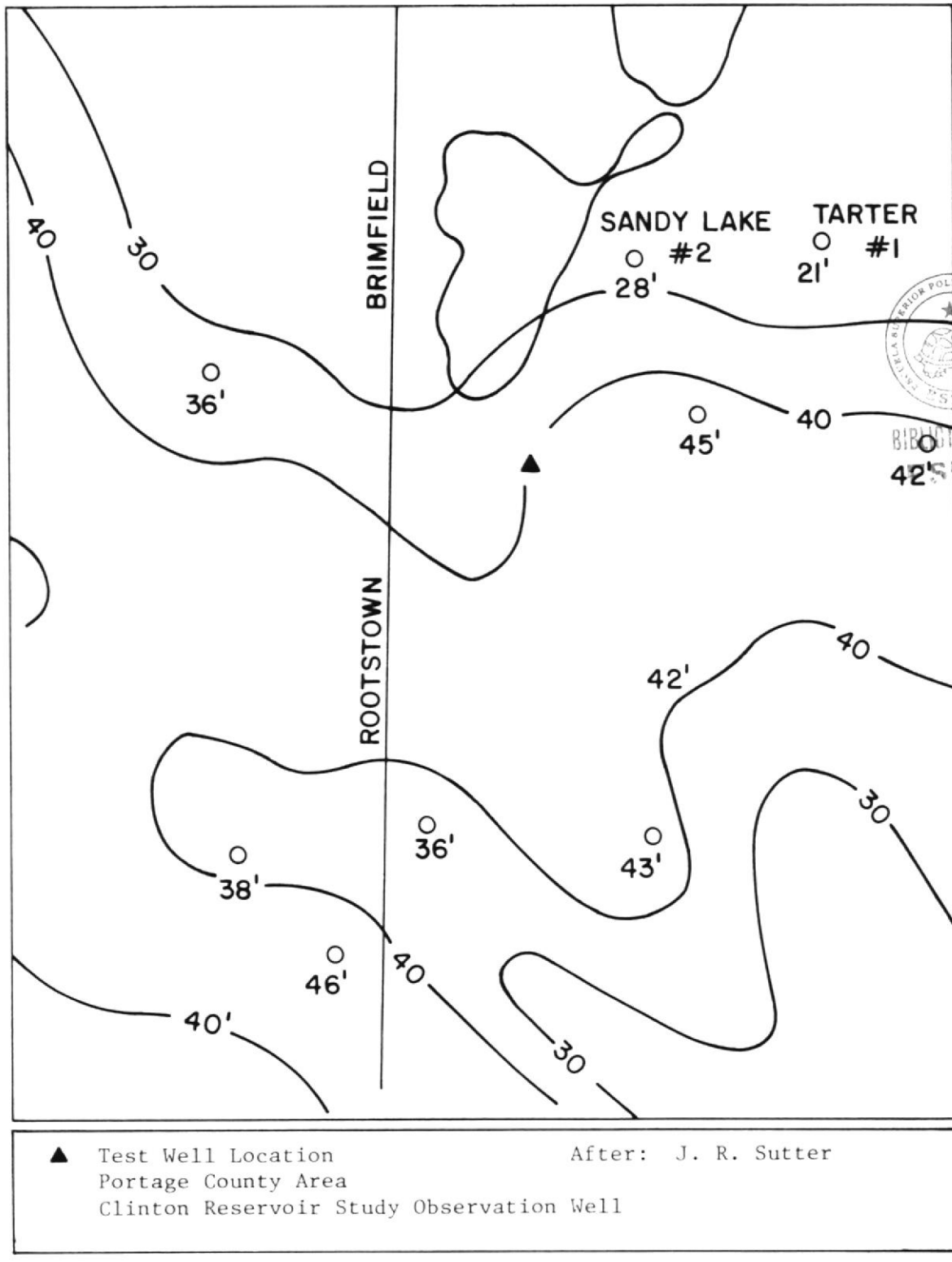


Figure 52. Isopach Base PSH - Top Red Clinton Sandstone

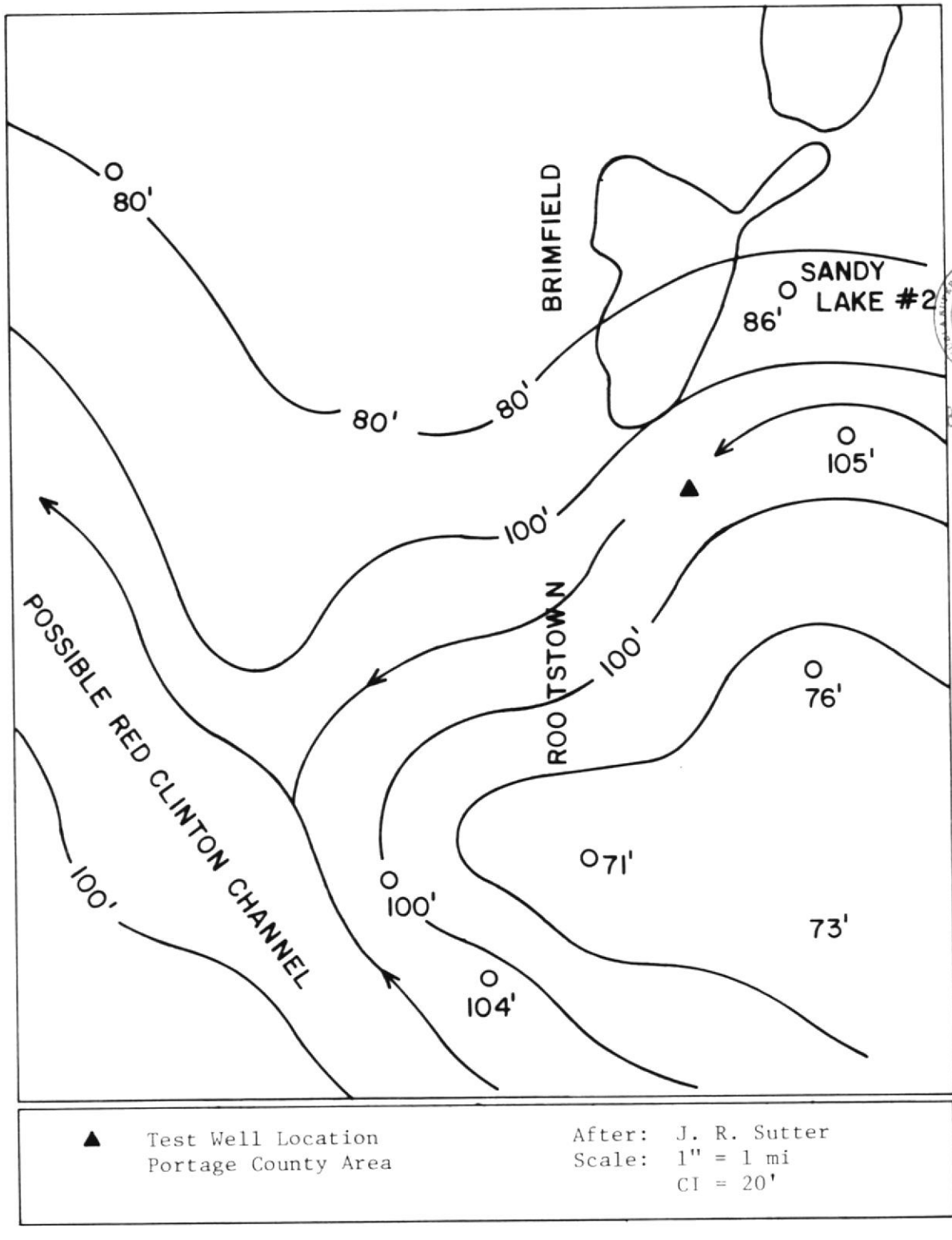


Figure 53. Isopach Base PSH - Base Red Clinton Sandstone

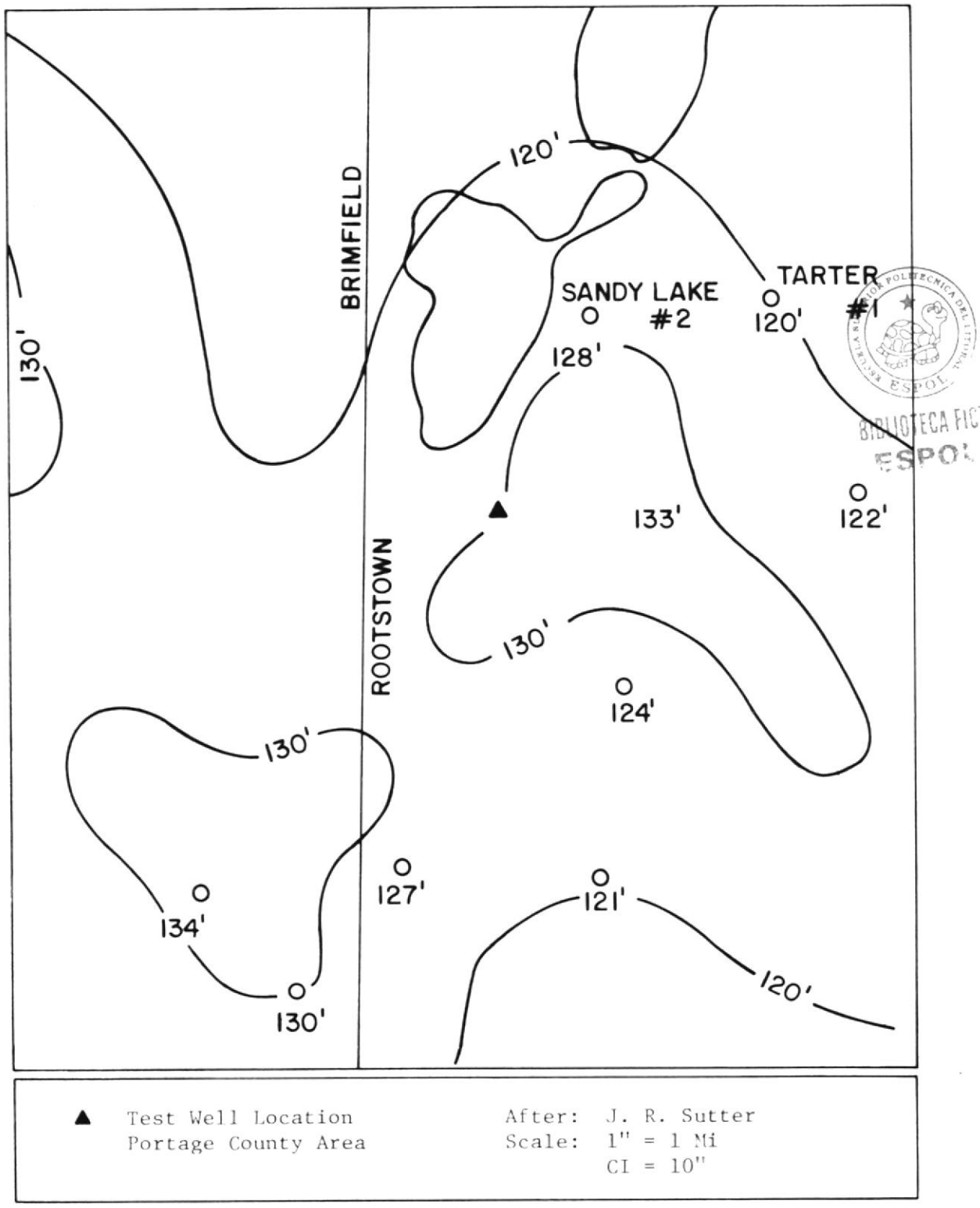


Figure 54. Isopach Base PSH - Base White Clinton Sandstone

TABLE 33

Core Analysis for Sandy Lake No. 3

Depth Feet	Permeability		Porosity	Residual Liquid Saturation % Pore Space	
	Horizontal	Vertical	%	Oil	Water
4247.5-49.0	<0.1	0.1	6.4	5.6	45.9
-50.3	"	"	7.0	4.5	67.9
51.6	"	"	6.2	7.3	52.0
52.5	"	"	6.1	5.1	50.0
53.8	"	"	6.6	5.4	39.4
54.9	"	"	6.6	4.5	37.0
56.2	"	"	6.8	8.6	43.4
57.2	"	"	6.0	13.0	39.2
58.4	"	"	7.6	4.7	32.7
60.0	"	"	5.9	1.8	74.3
61.4	"	"	5.3	0.0	77.8
62.9	1.5	"	6.0	3.8	59.0
64.3	<0.1	"	6.9	10.3	48.6
65.5	"	94	5.7	5.6	50.6
66.9	"	<0.1	5.7	5.1	67.6
68.0	"	"	7.1	6.7	35.5
69.3	"	"	7.1	10.0	35.3
70.7	"	"	7.1	16.6	36.9
71.4	"	"	3.5	-	97.7
72.6	1.4	"	8.2	12.2	41.6
73.9	<0.1	"	6.6	12.3	51.0
75.3	"	"	7.7	7.6	53.5
76.6	"	1.8	7.8	8.7	40.9
78.0	"	<0.1	6.8	20.6	40.0
79.5	"	"	6.1	16.1	43.4
81.0	18.0	"	5.8	10.3	58.6
82.1	<0.1	"	7.6	16.3	36.7
83.3	"	"	7.0	17.6	34.6
84.0	"	"	7.1	14.9	39.4
85.5	1.5	"	6.6	13.3	38.0
4290.9-92.0	<0.1	"	7.0	17.3	45.5
93.0	"	"	8.0	19.2	43.6
94.5	"	"	5.2	10.3	71.0
96.0	"	"	7.1	16.8	38.2
98.0	"	"	7.2	15.4	37.9
4325.0-26.8	"	"	7.7	13.3	28.4
28.9	"	"	7.8	15.3	26.7
29.2	"	"	7.1	15.3	30.6
30.9	"	"	6.7	12.6	28.0
32.2	"	"	6.9	19.3	32.7
33.6	"	"	6.2	14.4	32.7
35.5	"	"	6.3	14.2	37.1
36.5	"	"	6.6	16.4	32.8
36.9	"	"	6.5	18.8	32.1

TABLE 34

Core Summary

Formation	Depth, Feet	Feet Core Analyzed	Bulk Wet Density	Avg. Por. %	Avg. Liquid Sat.,% Oil	Water
Clinton	4247.5-4276.6	29.1'	2.53	6.5	7.0	51.0
	4276.6-4336.9	27.9'	2.52	6.8	15.4	38.4

TABLE 35

Description of the Formation Cored

Depth Interval(ft)	Description
CLINTON	
4225.0 - 4236.0	Sandstone, gray to white, very dense, occasional thin shale laminations.
4236.0 - 4238.0	Sandstone, red, heamtitic, very shaly.
4238.0 - 4239.0	Sandstone, gray to white, dense, vertical fracture.
4239.0 - 4242.5	Sandstone, red, silty, shaly.
4242.5 - 4244.0	Sandstone, red staining, very dense.
4244.5 - 4245.0	Sandstone, very shaly, gray.
4245.0 - 4249.0	Sandstone, gray to white, dense, shale laminations 4248-48.4.
4249.0 - 4258.5	Sandstone, slight red staining, fine grained, numerous thin carbonaceous lenses.
4258.4 - 4261.4	Sandstone, white to gray, fine grained, thin shale laminations, vertical fracture 4261.4-62.0 feet.
4261.4 - 4264.3	Sandstone, white, slight red stain, occasional thin carbonaceous lenses.
4264.3 - 4266.9	Sandstone, white, numerous thin shale laminations.
4266.9 - 4270.7	Sandstone, white to gray, fine grained.
4270.7 - 4271.4	Shale with sandstone laminations.
4271.4 - 4279.5	Sandstone, fine grained, white to gray, numerous thin carbonaceous lenses.
4279.5 - 4281.0	Sandstone, fine grained, white to gray, very shaly, 4273.9-79.0 feet vertical fracture, mostly hairline well healed, pink calcite and sandstone grains.
4281.0 - 4285.5	Sandstone, fine grained, white to gray, thin carbonaceous lenses.
4285.5 - 4290.9	Shale.
4290.9 - 4293.0	Sandstone, white to gray, fine grained, very clean.
4293.0 - 4295.0	Sandstone, white to gray, fine grained, very shaly.
4295.0 - 4298.0	Sandstone, white to gray, fine grained, very clean, vertical fracture 4296-97 feet.
4298.0 - 4306.0	Shale
4306.0 - 4312.0	Shale, sandstone laminations.
4312.0 - 4319.0	Sandstone, greenish-gray, very shaly.
4319.0 - 4325.0	Sandstone, greenish-gray, numerous shale laminations.
4325.0 - 4329.0	Sandstone, greenish-gray, fine grained, occasional shale laminations, shale very argillaceous, vertical fracture 4325-27 feet.
4329.0 - 4338.2	Sandstone, greenish-gray, fine grained, numerous shale laminations, very argillaceous, vertical fracture 4333-34 feet.
4338.2 - 4341.9	Shale, black, vertical fracture.

TABLE 36

Hydrocarbon Analysis of Formation Cored

Sample Interval	
4250 - 4258	Near top of Red Clinton, no show of gas or oil.
4258 - 4262.5	Slight bleeding of gas and oil.
4262.5 - 4263	Bleeding gas and oil along vertical hair line fractures 2-3 inches long and along small horizontal shale bedding planes.
4268 - 4277	Hard tight, no shows.
4277 - 4277.5	Very good show of gas and oil, large vertical fractures from 4275-5276.5 (unable to remove sample from large sample for fear of destorying sample for core analysis).
4277.5 - 4280	Slight show of gas and oil.
4294.4 - 4295	Good bleeding of oil and gas from horizontal bedding and permeability
4296 - 4297.7	As above.
4301 -	Good bleeding of oil and gas from shale partings.
4316.6 -	Gradiation sections no shows.
4322.3 -	Slight bleeding of gas, trace of oil.

Special Core Analysis Study

Core plugs, 1 inch in diameter, were drilled from the two full diameter well cores submitted for use in this study. Each core plug was extracted of hydrocarbons with Toluene, leached of salt with methyl alcohol, and then dried. Air permeabilities and Boyle's law porosities were determined on the cleaned and dried core plugs. Each core plug was evacuated and saturated with water containing 50,000 ppm sodium chloride.

The following studies were conducted by Core Lab:

Capillary pressure tests

Water permeability

Relative Permeability tests

With the exception of a final high-speed centrifuge point, a porous-plate cell and an air-brine system were used in performing the capillary pressure tests. Because of the low permeabilities and porsities of the sample tested, desaturation was minimal except at the higher pressures.

Capillary Pressure Tests

The primary use of these data is to relate water saturation to permeability or porosity and height above an oil-water contact in the reservoir. This information is subsequently used to calculate hydrocarbon in place. Other techniques used to arrive at this information are use of oil-base core water saturations and calcualtion of water saturations from electric logs. Of these three, capillary pressure and oil base core are considered the standard by most reservoir engineers.

The high cost of coring with oil-base mud makes capillary pressure tests the most practical and reliable technique for determining water saturation.

Conversion of capillary pressure data to height requires knowledge of reservoir oil (or gas) and water densities. Estimates must be made for (1) interfacial tension existing between reservoir fluids. Table 37 gives values of typical interfacial tension and contact angle constants and (2) the wettability of the reservoir as reflected in the contact angle between rock and fluids. The values assigned to these parameters are presented in Table 38. An important secondary use of capillary pressure data is to calculate the pore size distribution information and relative permeability characteristics.

The procedure followed for the capillary pressure tests was as follows:

A. Restored State

1. Water saturated samples for air - water of oil - brine tests and oil saturated cores for air - oil tests were placed on a semipermeable diaphragm, and a portion of the contained liquid was displaced with the appropiate fluid of oil or air. Liquid saturations were measured after equilibrium saturation was reached at each of several succesive pressure levels.
2. Three Phase Capillary Pressure Tests - these required a water saturated sample. The water was reduced to irreducible and the voided pores were saturated with oil. The oil was then displaced by the water to simulate water encroachement.

B. Centrifuge

Cores were saturated with water (or oil) and spun under air or oil at increasing speeds. Average liquid content at each speed was calculated from observations of liquid span out (liquid

TABLE 37

Air-Brine Capillary Pressure Data

Pressure, PSI:			1	2	4	8	15	35	300*
Sample Number	Perm. md.	Poros. %	Brine Saturation, Per Cent Pore Space						
1	0.24	8.7	100.0	100.0	100.0	100.0	100.0	97.2	30.3
4	0.07	6.7	100.0	100.0	100.0	100.0	100.0	59.5	32.1

TABLE 38

Typical Interfacial Tension and Contact Angle Constants

System	Δ Contact Angle	Contact Δ	γ Interfacial Tension	γ Cosine
Laboratory				
Air-water	0	1.0	72	72
Oil-water	30	0.866	48	42
Air-mercury	140	0.765	480	367
Air-oil	0	1.0	24	24
Reservoir				
Water-oil	30	0.866	30	26
Water-gas	0	1.0	50*	50

*Pressure and temperature dependent. Reasonable value to depth of 5000 feet.

volume out was read with the stroboscope while the centrifuge was in motion). The average saturation data were operated on matematically to stablish a water saturation versus pressure curve.

C. Mercury Injection

The test specimen was evacuated and mercury was injected in measured increments into the core at increasing pressure levels. In this type of test the mercury represents the non-wetting phase, equivalent to oil or gas in the reservoir. This was necessary mainly because of the low permeability of the samples.

Water Permeability

This test is the best indicator of formation sensitivity to various brines. It is used to evaluate damage to a formation that would occur from various drilling filtrates and / or injection waters. A loss of permeability may be due to :

(1) Swelling clays such as montmorillonite or,

(2) particle movement and subsequent pore blockage by fines or clays such as Kaolinite.

The tests consisted of direct measurement of permeability during the flow of water through a saturated sample. Permeability to water as a function of throughput is normally recomended.

To differentiate between clay swelling and particle movement, flow through the sample in a reverse direction was made. This is necessary since a decrease in permeability could be because a particle movement, a sharp increase in permeability on the reverse flow test indicates moving particles. The reverse flow dislodges the particles from pore

necks where they heve accumulated and temporarily caused increased permeability.

Relative Permeability Tests

Darcy's law as originally stated applies to a porous medium where a single fluid completely saturates the rock. When two or more fluids are present, they compete for the flow space within the rock and it is important to know the effective permeability and relative permeability of every one of the fluids flowing through the rock. The effective permeability and the relative permeability require that the saturation of the phases be known before much practical use can be made of the data. The saturation present is dependent on the wetting characteristics of the rock and the saturation history of the sample. In general, laboratory samples should follow the same sequence of saturations changes during preparation and test that the reservoir has undergone.

Gas - oil relative permeability data is used in conjunction with fluid properties and material balance equations to predict pressure, gas - oil ratio and production performance for solution - gas drive reservoirs . K_g/K_o is also required for gas cap advance, gravity drainage, productivity decline, gas - coning and fractional flow equations .

K_g/K_o tests were run with connate water (14% initial water saturation for sample 2B, and 11.4% for sample 3). This was necessary, since Clinton sandstones are known to be water sensible because of the presence of hydratable clays, and also because of the low permeabi-

lity that characterizes Clinton. Also, since this test only alows two mobile phases, when water is present it should be immobile. These tests were conducted on extracted, restored cores.
Tables 39 to 41 give the data obtained from these special core analyses. Figure 55 to 58 show in a graphical manner the relative permeability curves as well as the relative permeability ratio curves.

When the relative permeability to oil was being measured, oil was dynamically displaced by gas and incremental volumes of oil and gas production were measured as a function of time. Gas - oil relative permeability characteristics were calculated from the production data. It was interesting to notice that the oil displacement efficiency by gas was above average for sandstones of the Clinton type.

Synergetic Computer Processed Interpretation

Schlumberger conducted a computer processed interpretation (Schlumberger Synergetic Log Systems) of the control well. The analysis was made at intervals of 1 foot, from 602.0 to 4342.0 feet (only the Caliper Log was run from 100.0 to 4300.0 feet). From this analysis the following parameters were determined : Kerogen volume,water saturation, porosity, total and secondary matrix density, shale volume. From these studies it was possible to determine appreciable hydrocarbon accumulation in the shale gas section of the hole. They look so promising that the possibility of a dual completion in the control well at some later time was suggested.

TABLE 39

Description of the Samples

Company	- The East Ohio Gas Company	Formation	- Clinton
Well	- Sandy Lake Land Co.No.3, Well No. 3212	County	- Portage
Field	-	State	- Ohio

Identification and Description of Samples

Sample Number	Depth, Feet	Lithological Description
1	4271'-72'	Ss, gry, v/fn grn, well indurated, w/iron stains & pockets
2B	4271'-72'	Ss, gry, v/fn grn, well indurated, w/iron stains
3	4284'-85'	Ss, gry, v/fn grn, well indurated, w/iron stains
4	4284'-85'	Ss, gry, v/fn grn, well indurated, w/iron stains

TABLE 40

Gas-Oil Relative Permeability Data

Sample Number 2B

Air Permeability, Md. 0.35

Oil Permeability at Initial Water Saturation, Md. 0.27

Initial Water Saturation Per Cent Pore Space 14.0

Porosity, Per Cent 7.7

Liquid Sat. % Pore Space	Gas-Oil Relative Perm. Ratio	Relative Perm. to Gas*, Fraction	Relative Perm. to Oil*, Fraction
100.0		.000	1.000
89.2	.00056	.00029	.520
86.7	.00097	.00043	.445
84.5	.0029	.0011	.380
81.8	.0067	.0021	.315
78.6	.019	.0047	.250
75.7	.055	.011	.200
72.7	.113	.018	.159
68.4	.371	.040	.107
66.9	.608	.055	.090
63.3	1.45	.095	.065
61.0	2.49	.123	.049
58.6	4.35	.161	.037
55.8	7.47	.203	.027
52.7	13.6	.260	.019
48.8	26.7	.320	.012
45.0	57.4	.390	.0068

TABLE 41

Gas-Oil Relative Permeability Data

Sample Number 3

Air Permeability, Md. 0.35

Oil Permeability at Initial Water Saturation, Md. 0.28

Initial Water Saturation Per Cent Pore Space 11.4

Porosity, Per Cent 7.1

Liquid Sat. % Pore Space	Gas-Oil Relative Perm. Ratio	Relative Perm. to Gas*, Fraction	Relative Perm. to Oil*, Fraction
100.0		.000	1.000
86.5	.0020	.0011	.558
84.4	.0038	.0019	.505
81.6	.0086	.0038	.441
78.9	.018	.0069	.380
75.8	.040	.013	.321
72.6	.085	.023	.270
70.1	.154	.036	.235
66.9	.306	.055	.179
63.9	.577	.079	.137
61.1	1.10	.110	.100
57.6	2.12	.146	.069
54.4	3.84	.177	.046
50.8	7.69	.223	.029
46.7	16.9	.270	.016
42.8	40.0	.340	.0085
38.0	103	.400	.0039

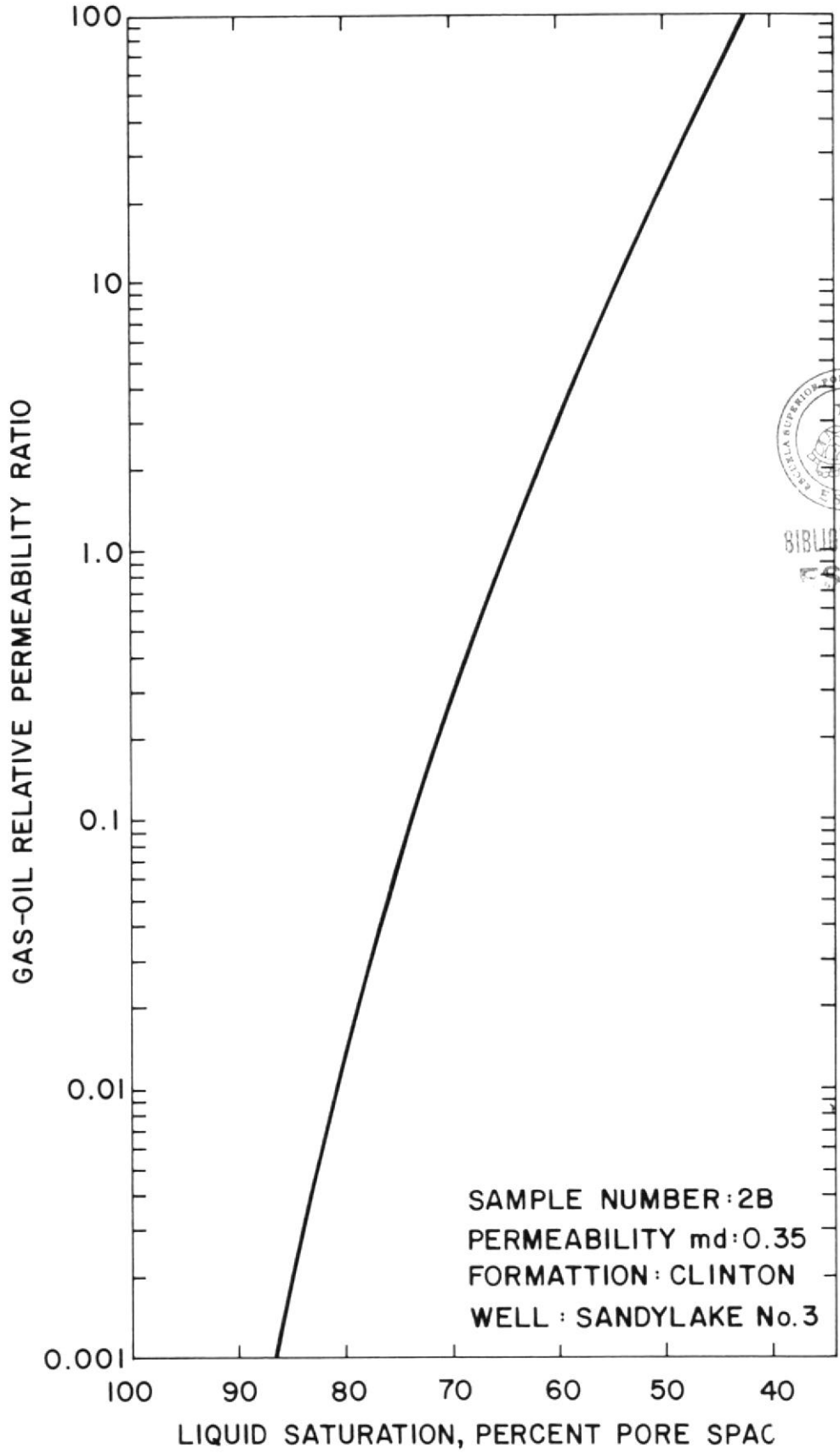


Figure 55. Gas-Oil Relative Permeability Ratio, Sample 2B

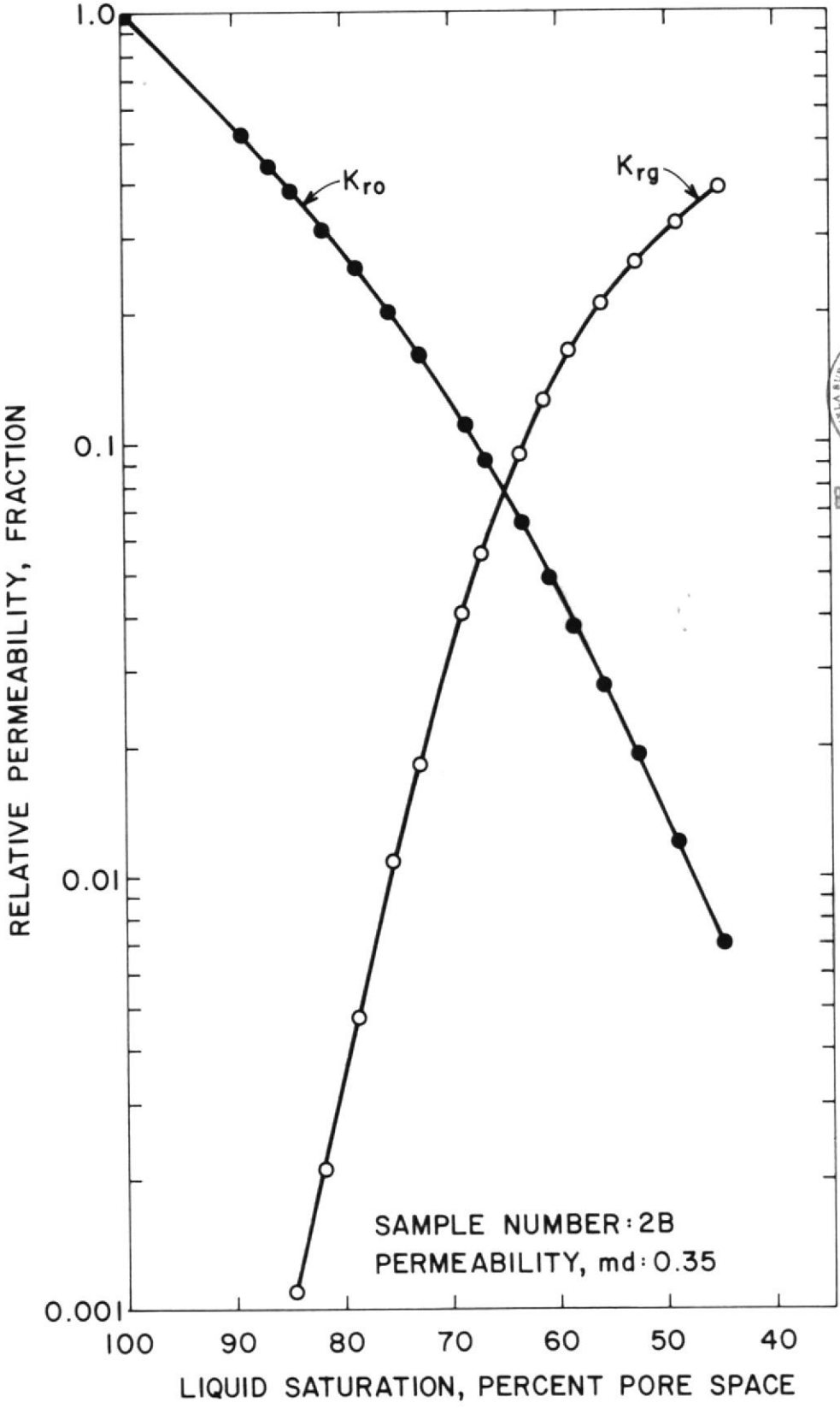


Figure 56. Gas and Oil Relative Permeability, Sample 2B

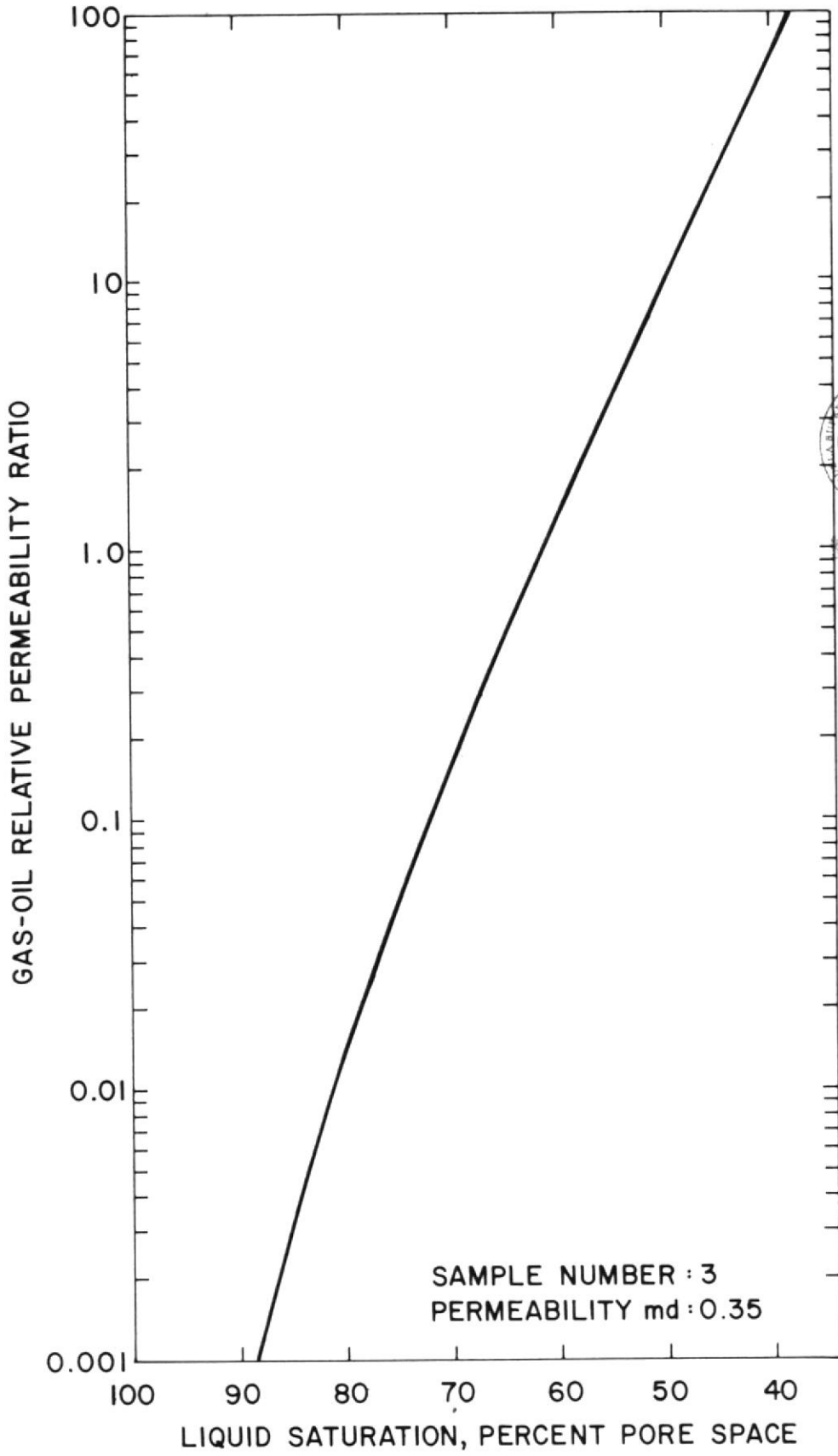


Figure 57. Gas-Oil Relative Permeability Ratio, Sample 3

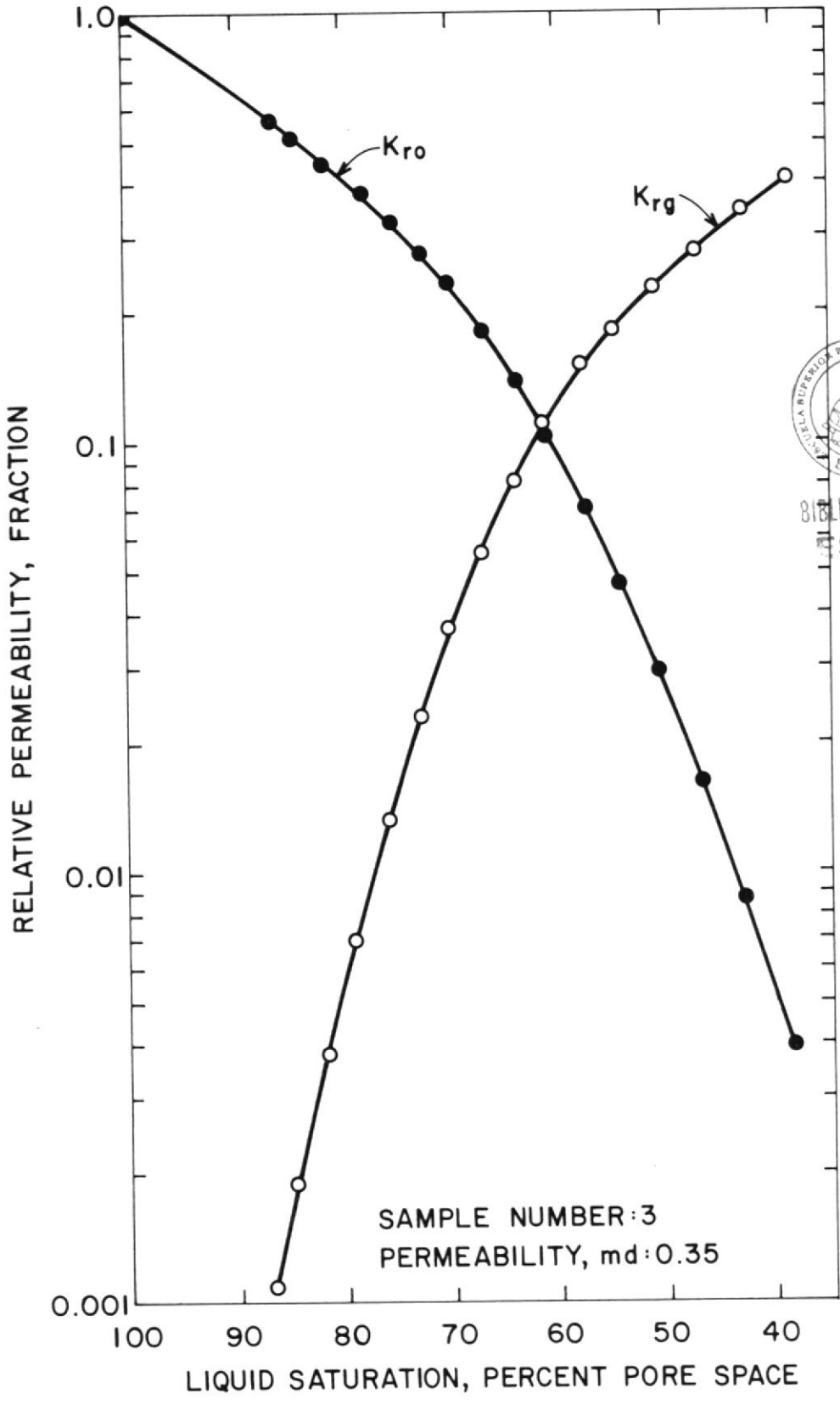


Figure 58. Gas-Oil Relative Permeability Ratio, Sample 3. (0.35 md.)

Fluid Analyses

(i) Water Analysis. Table 42 shows the results of the water analysis conducted in water samples from the control well, even though the analysis shows a typical formation water, calcium, magnesium and $CaCo_3$ are the ones that cause scaling and recipitates on the production equipment.

(ii) Gas Analysis. Table 43 is a normalized chromatographic analysis of the gas samples from Sandy Lake No. 3. The analysis was conducted for hydrocarbons from methane to hexanes plus the analyses included sulfur content. From this table it can be seen that the produced gas is very dry (98.38% methane, with only 2.27% of propane plus).

(iii) Stock Tank Oil Analysis. Even though this reservoir is considered to be a gas reservoir, some high paraffin Penn Grade crude oil is produced along with the gas and super-saturated salt water. The high paraffin content of the crude oil creates many problems in that it preciptates out in the tubing, on the sand face and within the fractures resulting from stimulation jobs.

Table 44 shows the results of the stock tank oil analysis. The API gravity of this oil was 39.3° API (@ 60°F), and most of this oil was made up of pentadecanes plus (67.20% by weight).

Core Analysis, Immersion Tests, X-Ray Analysis, Rock Properties Measurements and Fluid Loss Tests

These tests were not conducted with cores from Sandy Lake No. 3, but the cores studied came from Red Clinton (4501 feet) and White Clinton (4527 feet). Two formation core samples from Red Clinton and White Clinton were analyzed.

TABLE 42

Water Analysis

Date: October 10, 1975

Company The East Ohio Gas Company

Lease: Sandy Lake

Well: Sandy Lake 3

Formation: Clinton

County: Portage

Specific Gravity:	1.205 @ 68°F	TDS	295,000 ppm*
pH	4	Sulfate (So_4)	175 ppm*
Chloride (Cl)	160,000 ppm*	Iron (Fe)	398 ppm*
Total Hardness ($Ca\ Co_3$)	126,000 ppm*	Sulfide (S)	none present
		Bicarbonate (HCO_3)	ND ppm*
Calcium (Ca)	43,600 ppm*	NH_3/N	very strong trace
Magnesium (Mg)	4,131 ppm*	T3L	very strong trace

Comment: *indicates data determined for mpl
ND - not determined

TABLE 43

Gas Analysis

Date: October 23, 1975

Company: The East Ohio Gas Company

Lease: Sandy Lake

Well: Sandy Lake No. 3

Formation: Clinton

County: Portage

Gross Heating Value as BTU/SCF - 1041 (Cutles-Hammer recording Cal.)
(30.00" of 32°F Hg, 60°F, dry) - 1043.8 (Calculated from Chromatographic Analysis)
- 1043.7 (Caldwell)

Specific Gravity
(Dry air = 1.000) - 0.630 (Ranarex specific gravity instrument)
- 0.6302 (Calculated from chromotographic Analysis)
- 0.6303 (Caldwell)

Sulfur Analysis	Grains as sulfur per 100 SCF	Parts per million as sulfur by weight
Sulfur-Containing Constituent		
Hydrogen Sulfide	0.00	0.0
Mercaptans (as n-butyl mercaptan)	0.06	1.8
Sulfides (as diethyl sulfide)	0.13	3.9
Residuals (as diethyl sulfide)	0.44	13.0
Total Sulfur	0.63	18.7

Normalized Chromotagrphic Analysis

Constituent	Calculated Volume Percent
Helium	-
Hydrogen	0.0
Oxygen	0.38
Nitrogen	4.75
Methane	87.38
Ethane	5.12
Carbon Dioxide	0.10
Propane	1.42
Iso-Butane	0.38
Neo-Pentane	0.00
Iso-Pentane	0.11
Normal Pentane	0.11
Hexanes Plus	0.06
Total	100.00

TABLE 44

Stock Tank Oil Analysis

Component	Mol Percent	Weight Percent	Density @ 60°F Grams Per CE	°API @ 60°F	Molecular Weight
Hydrogen Sulfide	Nil	Nil			
Carbon Dioxide	Trace	Trace			
Nitrogen	Nil	Nil			
Methane	Nil	Nil			
Ethane	0.02	Trace			
Propane	0.07	0.01			
Iso-Butane	0.04	0.01			
N-Butane	0.18	0.05			
Iso-Pentane	0.27	0.09			
N-Pentane	0.47	0.15			
Hexandes	1.59	0.60			96
Heptanes	5.51	2.38	0.7163	65.9	106
Octanes	9.32	4.44	0.7382	60.0	117
Nonanes	8.81	4.63	0.7555	55.6	131
Decanes	10.26	6.03	0.7691	52.3	140
Undecanes	6.22	3.91	0.7777	50.3	160
Dodecanes	5.63	4.04	0.7862	48.3	177
Tridecanes	4.28	3.41	0.7927	46.8	190
Tetradecanes	3.57	3.05	0.8010	45.0	342
Pentadecanes+	43.76	67.20	0.8602	32.8	
	100.00	100.00			

°API gravity @ 60°F of STock TAnk OIl - 39.3

The X-ray analysis indicated the presence of small to moderate amounts of water sensitive clays in the submitted sample from the Red Clinton formation, and very small to small amounts of these clays in the White Clinton formation sample. When water sensitive clays are present in these amounts, it is recommended that the formation be treated with a hydrocarbon base fluid, or with a water base fluid such as two percent clay fluid or two percent potassium chloride water.

The core samples tested showed very low permeabilities to air, and therefore Fluid Loss Tests were considered unnecessary. The results of the laboratory tests are given in Table 45.

TABLE 45

Core Analysis

Formation	Core No.	Depth Feet	Por. %	Air Perm. (md) Horiz.	Air Perm. (md) Vert.	Sol. %	Salt Content, mg. Salt/100 gm. Core
Red Clinton	1	4501	1.4	<0.01	<0.01	8	300
White Clinton	2	4527	5.5	0.66**	0.03	5	300

This is solubility in dilute hydrochloric acid as calcium carbonate only.
This test plug contained a hairline fracture.

Immersion Test

Effects of immersion under vacuum at 115°F(est. BHT) for one hour in the following:

Formation	Core No.	Depth Feet	Fresh Water	10% NaCl	2% KCl	2% Clay-Fix	7 1/2 6% MCA HF	Ker.
Red Clinton	1	4501	V-SAF	V-SAF	V-SAF	NFR	NFR MAF	NFR
White Clinton	2	4527	NFR	NFR	NFR	NFR	V-SAF	NFR NFR

NFR = No fines released.
V-SAF = Very small amount fines.
SAF = Small amount fines.
MAF = Moderate amount fines.

X-Ray Diffraction Analysis

Core No.	1	2
Depth (ft)	4501	4527
Quartz	major	major
Feldspars	very small	small
Calcite	-	-
Dolomite	small-moderate	-
Kaolinite	small	small
Illite	small-moderate	very small
Montmorillonite	very small	very small
Mixed Layer Clays	small-moderate	small
Anhydrite	very small	small
Siderite $FeCO_3$	-	small

Rock Properties Measurements

Core No.	Depth (feet)	Formation	Poisson's Ratio	Young's Modulus of Elasticity (Psi)
1	4501	Red Clinton	0.09	5.71×10^6
2	4527	White Clinton	0.098	5.52×10^6

Fluid Loss Tests

The submitted core was not permeable enough to conduct fluid loss tests.

APPENDIX C

THERMAL STIMULATION EQUIPMENT AND PROCEDURE

Thermal Stimulation Equipment

The following equipment was involved in the project:

Air Compressor shown in Figure 59 (top) with a capacity of 350 Mcf per day, 1500 psig discharge.

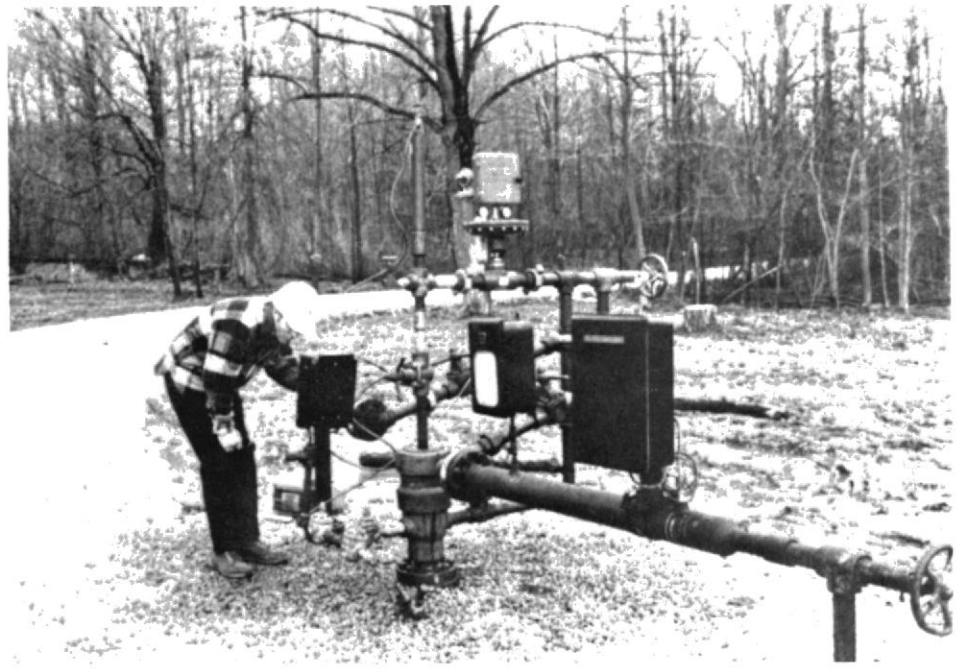
Metering and Transmission Air System consisting of 2 inch pipe for connecting the air compressor to the well head. One check valve, one orifice run to meter air injection, one 2 inch valve ahead of orifice run, 2 inch and 1 1/4 inch fittings. The air metering system is presented in Figure 59 (bottom).

Well Head Equipment consisting of one 4 inch x 2 inch x 2 inch tubing head, two full opening valves (1 1/2 inch or 2 inch line pipe), a small rig to hold the wire line which holds the down hole burner, Figure 60 (bottom) shows the well head set up.

Gas Compressor shown in Figure 61 (bottom). This machine is water cooled with a maximum capacity of about 20 Mcfd. Fuel gas is compressed to necessary pressure and discharged through an orifice meter at closely regulated rates. Figure 61 (top) shows the integral orifice. DP cell gas meter as well as the air injection meter. Under adiabatic conditions the temperature of the air delivered to the formation can be controlled by adjusting the air-gas ratio.

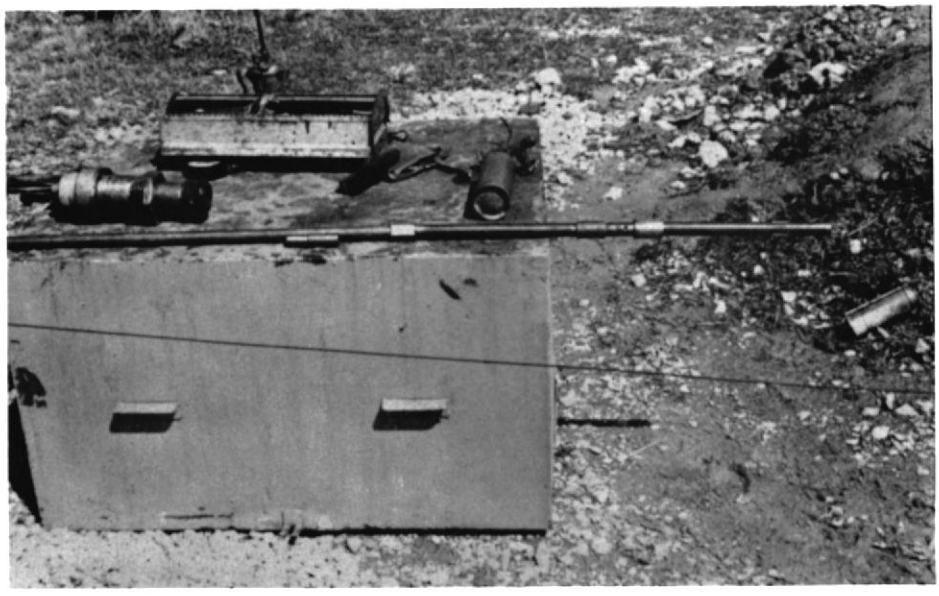
Wellbore Set up, consisting of a string of new tubing (1 1/2 inch or 2 inch) at the end of the tubing stainless steel shells are lined with a retractory material which confines the gas flame temperatures inside the shield. Finally, the down hole burner shown in Figure 60 (top), was run into the hole through the tubing by a wire line. Gas entered through the 2 inch tubing and in through the casing. A nitrogen tank near the well head (see Figure 60, bottom) was used while loading the ignition chemical (triethyl-Borade) in the burner.

AIR COMPRESSOR

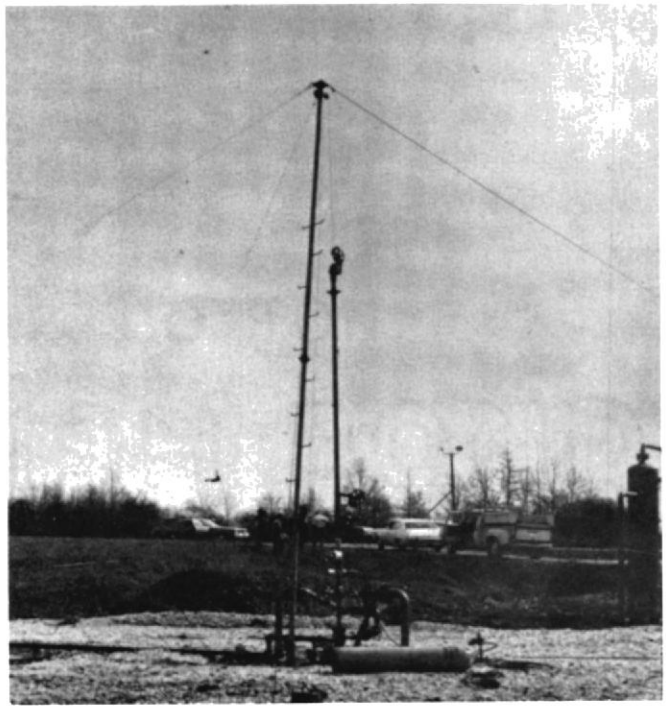


METERING AND TRANSMISSION AIR SYSTEM

Figure 59. Air Injection System



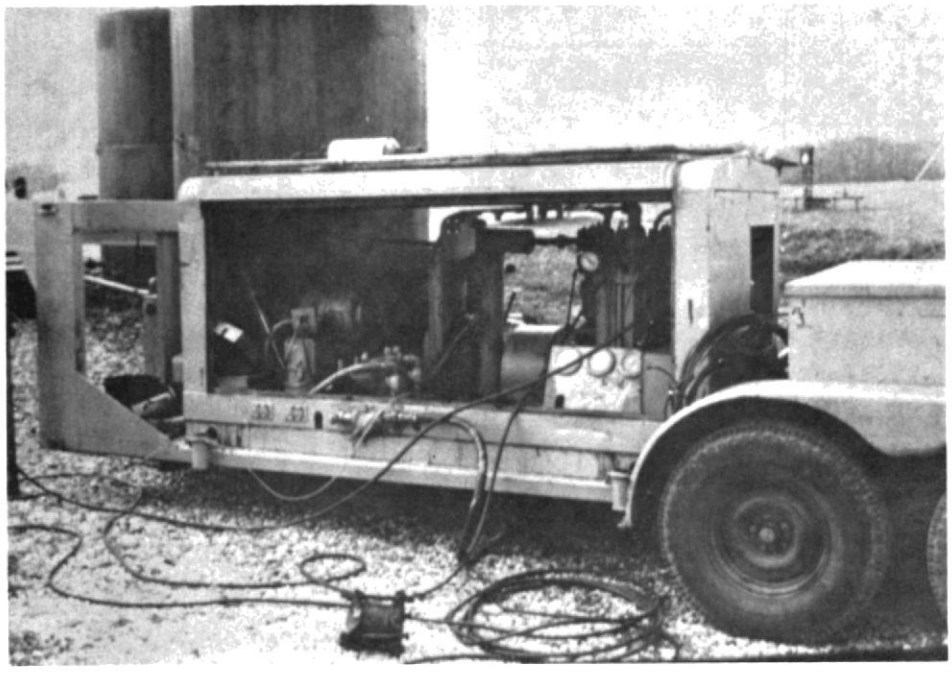
DOWN HOLE BURNER



WELL HEAD SET-UP

Figure 60. Down Hole Burner and Well Head Set-up

INTEGRAL ORIFICE DP CELL GAS METER



GAS COMPRESSOR

Figure 61. Gas Injection System

Procedure

1. The production casing was swabbed to remove all oil and other liquids.
2. Sometimes it was necessary to cover the perforations with water so that any oil left in the casing will float on top of the water and away from the burning zone.
3. The stainless steel heat shield lined with a refractory material was attached to the bottom of the tubing. The shield was used to confine the gas flame temperature to the shield and protect the casing from heat damage.
4. The tubing was run to a depth so that the heat shield was positioned a few feet above the perforations. This set up is shown in Figures 41 and 43.
5. An ignition chemical (Tri-ethyl Borade) was placed in the down-hole burner. Nitrogen was injected with the ignition chemical as a safety measure to separate the gas air interface.
6. The burner was lowered in the tubing on a wire line through a lubricator. To insure the burner remains inside the heat shield a setting nipple was adapted between the shield and the end of the tubing.
7. The gas was injected down the tubing while the air was injected down the casing-tubing annulus.
8. As the air came in contact with the ignition chemical in the down hole burner a slow ignition takes place. Ignition generally takes place around 900°F with the actual burn reaching 1100°F - 1200°F.
9. The actual time of ignition was difficult to detect. Air in-

jection performance and gas analysis were used to determine if combustion has occurred. Normal ignition time lasted between 5 and 10 days.

10. As the gas burned inside the heat shield the air flows around and through the heat shield and transferred heat down hole to the formation.
11. The temperature of the air delivered to the formation was determined and controlled by adjusting the air-gas ratio.
12. Increases in bottom-hole pressure were taken as positive indications of combustion in the burner.
13. Once it was established that the burning was taking place, the down hole burner was removed from the well, but the air injection was continued for another two weeks.
14. Once the burn was completed, the well was flowed back under controlled conditions.
15. Prior to putting the well back into production a gas analysis was taken.
16. Prior to thermal stimulation and after the stimulation, back pressure tests, and pressure build up tests were conducted in order to evaluate the results from the stimulation.

Method for Restoring Productivity to Gas Wells in the Clinton Sand of Ohio, a Laboratory and Field Experiment

by

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ABSTRACT

A series of laboratory experiments were conducted to determine the most efficient method to remove paraffin deposits in the well bore and fracture system of gas wells in the Clinton Sand of Ohio.

After experimenting with Ultrasonic Energy, solvent stimulation and thermal stimulation, it was concluded that the thermal stimulation method was the most attractive for field trials. After designing a pilot project consisting of three wells, two of these wells where the paraffin problem was evident were thermally stimulated using a down hole gas burner to create a high temperature gradient from the well to the fracture system and formation. After several days of stimulation it was observed that the wells were indeed stimulated but not to the magnitude originally expected, mainly because of the extremely low permeability of the formation involved and because of the low pressure gradient existing in the stimulated wells.

VITA

Boris Patricio Abad-Guerra was born in La Libertad, Salinas, Ecuador, on March 14, 1947, the son of Leonardo Abad A. and Sara Guerra de Abad. He graduated from Colegio Josefino Rubira, Salinas, Ecuador in 1965. He finished his studies in Petroleum and Natural Gas Engineering at the Escuela Superior Politecnica del Litoral, Guayaquil, Ecuador. In December, 1972, he received a LASPAU (Latin American Scholarship Program of American Universities) and the Fulbright scholarship and entered The Pennsylvania State University. Upon the completion of his thesis, "Thermal Miscible Displacement Studies in the Athabasca Tar Sands" he received the Degree of Master of Science in March 1975. In March 1975, he was granted an assistantship at The Pennsylvania State University to pursue his doctoral studies. Mr. Abad is a member of the Society of Petroleum Engineers of AIME. While he was at The Pennsylvania State University he co-authored a paper with S. M. Farouq Ali, "Bitumen Recovery from Tar Sands, Using GCOG Synthetic Crude as Solvent in Conjunction with Steam", presented at the 26th Annual Technical Meeting of the Petroleum Society of CIM, June 11-13, 1975.