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Mechanisms of Formation Damage in Matrix-Permeability Geothermal Wells

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MECHANISMS OF FORMATION DAMAGE IN MATRIX-PERMEABILITY GEOTHERMAL WELLS*

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ABSTRACT

Tests were conducted to determine mechanisms of formation damage that can occur in matrix permeability geothermal wells. Two types of cores were used in the testing, actual cores from the East Mesa Well 78-30RD and cores from a fairly uniform generic sandstone formation. Three different types of tests were run.

The East Mesa cores were used in the testing of the sensitivity of cores to filtrate chemistry. The tests began with the cores exposed to simulated East Mesa brine and then different filtrates were introduced and the effects of the fluid contrast on core permeability were measured. The East Mesa cores were also used in the second series of tests which tested formation permeability during long-term exposure to fluids. The generic sandstone cores were used in the third test series which investigated the effects of different sizes of entrained particles in the fluid. Tests were run with both single-particle sizes and distributions of particle mixes.

In addition to the testing, core preparation techniques for simulating fracture permeability were evaluated. Three different fracture formation mechanisms were identified and compared. Measurement techniques for measuring fracture size and permeability were also developed.

*Work performed under Sandia National Laboratories Contract No. 46-8747 for the U.S. Department of Energy, Division of Geothermal Energy.

TABLE OF CONTENTS

LIST OF FIGURES

List of Figures (continued)

List of Figures (continued)

LIST OF TABLES

INTRODUCTION

"Formation damage" is a term used throughout the industry to describe negative interaction between the drilling operation and the producing formation(s) resulting in an impaired near-wellbore permeability and subsequent reduction in production. In geothermal wells, where economic viability is predicated upon the production of large amounts of hot water and/or steam, formation damage must be understood, controlled and minimized.

Formation damage is a complex problem and no unique, definitive solution exists at present. Numerous researchers[1,2,3,4] have addressed various aspects of this problem, generally from the perspective of oil/gas production. Solutions and understandings so generated have not always had successful transitions to geothermal applications (e.g., completions, workovers).

In general, formation damage is minimized in wellbores where air drilling is possible. Unfortunately, due to formation pressure and quality, air drilling is usually not practical and muds are used. Whenever drilling muds are introduced into the borehole, particularly in an over balanced pressure situation, mud invasion and formation damage occur[1]. Hydrothermal wells are particularly sensitive to this invasion because of the typically long completion zones, complex chemistries and high temperatures encountered which result in a variety of unknown reactions. Solids plugging, precipitation, matrix/filtrate interaction, or any combination of these can result in serious near-wellbore permeability impairment.

The mechanisms of geothermal formation damage discussed in this report are divided into three major categories: mud filtrate induced damage, low salinity formation brine effects, and particulate induced damage. Most prior laboratory testing has focused upon matrix permeability dominated reservoirs such as East Mesa. However, a large portion of geothermal resources depends upon fractures for its primary production; therefore, it is necessary to simulate fractured formations in the laboratory to properly assess the interaction of drilling fluids with many geothermal formations. A final section in this report discusses the best methods of simulating a naturally occurring fracture in the laboratory.

This work has been funded by the Geothermal Drilling and Completion Technology Development Program at Sandia National Laboratories.

TEST PROGRAM OBJECTIVES

An extensive series of core tests was performed under simulated downhole conditions to determine: (1) the extent of core sensitivity to mud filtrate chemistry, (2) the impact of long-term testing on reservoir permeability, and (3) the effectiveness of various particle sizes and combinations of sizes in avoiding loss of permeability. A discussion of the reasons for conducting these three test programs and the work done to develop simulated fractures in the laboratory is presented below.

Filtrate Chemistry Sensitivity

Equilibrium pore fluid chemistry is a result of a temperature and pressure dependent interaction of a wide variety of solid and gaseous solutes. When filtrate from the drilling mud displaces the formation pore fluid surrounding the well bore, a salinity contrast can exist that disturbs the clay equilibrium and can be potentially detrimental to the productivity of the well. Ionic exchange between the filtrate and the clay minerals can result in clay hydration accompanied by clay swelling. Swollen clays within the pore throats will significantly reduce permeability. A more serious problem is encountered when these swollen clays become detached from the pore walls, disperse within the pore fluid and congregate at pore throat restrictions causing an effective blockage of flow. Gray and Rex[6] have demonstrated that clay dispersion and permeability impairment can occur even when only small percentages of clay are present within the pore space.

It has also been demonstrated by Jones[3] that the invading filtrate, when dominated by an ionic species known to reduce clay hydration, can actually stabilize the formation clays and subsequently minimize permeability impairment. The influence of elevated temperatures upon this phenomenon is not well understood at present.

Recognizing that interaction between the producing formation (matrix and pore fluid) and the drilling fluid filtrate (the liquid fraction of the drilling fluid) can result in a reduction or an impairment of the formation permeability, an experimental program was designed to investigate permeability alterations due to salinity contrasts. Four different filtrate solutions, 3% KCl, 3% $CaCl_2$, 3% NaCl and deionized water were tested at four temperatures ranging from 23°C to 250°C to determine East Mesa core sensitivity to these filtrates.

Long Term Permeability Tests

Due to an unexpected decline in permeability of the East Mesa core to the synthetic pore fluid at the beginning of each filtrate chemistry test, five permeability tests were conducted for durations ranging from 40 hours to 7 days. The objective of these long term permeability tests was to isolate the factor or factors contributing to significant decreases in permeability as a result of pore fluid/formation interaction.

Particle Size and Distribution

Particle Size: During the internal filter cake generation in the wellbore, both mud solids and mud filtrate enter the formation. Clay solids and drill cuttings that are smaller than the pore openings will be deposited within the formation. As these particles accumulate, successively smaller particles are "filtered" out. Eventually an internal filter cake is formed and greatly reduces further mud penetration into the formation. Filtrate, although inhibited, can migrate through this "cake" and this constitutes the fluid loss to the formation. The complete process can be controlled to a certain extent by designing the mud to include specifically sized particles, termed bridging particles.

Abrahms[1] has shown that in typical petroleum wells, the effectiveness of the bridging material in reducing particle invasion is a function of the concentration and particle size of the material, and of the pore sizes of the formation rock. It also has been demonstrated that backflushing will remove very little of the particulate matter deposited during this cake formation. In a geothermal situation where increased temperature will cause gelation of the clays, the removal of this internal filter cake is much more difficult.

Particle Size Distribution: Abrahms[1] has demonstrated the significance and relationship of particle size to the bridging process. It is important to understand the effect of "bridging" particle size distributions within the drilling fluid. Total particulate distribution within the drilling fluid will change as the mud is "broken in", as different formations are penetrated, and as some particles are screened out by solids removal equipment. Significant variations of critical "bridging" sized particulate may require the addition of inert particulate to maintain adequate numbers of particles in these ranges.

It, therefore, was the purpose of this section of the test program to determine and document the particle size, and distribution of particles, which most effectively bridge off the formation. The influence of simulated downhole temperatures of 175° and 250°C was additionally introduced in the particle size and distribution testing in an attempt to quantify the effects of temperature on particle bridging behavior.

Laboratory Simulation of Fractures

Geothermal reservoirs can be classed into: (1) matrix-dominated reservoirs, (2) fracture-dominated reservoirs, and (3) combined fracture-matrix dominated reservoirs. Outstanding examples of each exist; the East Mesa KGRA produces from a matrix permeability-dominated sandstone, in the Geysers production is strictly from fractures in the otherwise low-permeability Franciscan Graywacke. In the Salton Sea, possibly both fractures and matrix permeability contribute to production. To date, the majority of formation damage research done has focused upon low temperature matrix permeability-dominated reservoirs, since these were commonly encountered in oil and gas exploration, and laboratory test procedures were naturally easier to devise.

With greater activity in geothermal exploration, many good hot water and steam targets are found to be fracture dominated resources and cannot be treated in the conventional oil and gas manner. While lost circulation in a geothermal well can be as great or more difficult a drilling problem than those encountered in petroleum wells, there exists the need to treat the fractures causing lost circulation with far greater care because of their contribution to geothermal production. Therefore, a need exists to see that a complete evaluation of fractures is undertaken. The broad scope of the subject combined with the scientific controversy over definitive fracture theory makes it a difficult task to undertake.

The groundwork laid at Terra Tek in the previous two years' research conducted on characterizing a matrix permeability geothermal reservoir and formation damage mechanisms as they relate to drilling and formation induced disturbances made this the appropriate study to begin basic research into laboratory simulation of naturally occurring fractures. It was not the intent of this project to decide on the definitive fracture model. Instead, the objective was to provide the engineering design and technique to 1) evaluate various fracture simulations suitable for laboratory use, 2) determine the most effective sample preparation method, and 3) achieve a test system with the capacity to handle increased rates of flow.

CORE MATERIAL DESCRIPTION

Two types of core material were used as test samples in this formation damage study. In tests conducted to assess filtrate chemistry sensitivity and long term permeability effects, sandstone core samples were obtained from a production zone of a geothermal well in the East Mesa KGRA, Imperial Valley, California. A fine grained sandstone of a generic nature was selected for the particle size and distribution testing portion of the study. Both materials are described in detail in the following section.

East Mesa Sandstone

The sandstone core samples used in the filtrate sensitivity and long term permeability tests were from the 5500 foot zone of Republic Geothermal Well 78-30RD, located in the East Mesa KGRA, Imperial Valley, California (Figure 1). The reservoir is a matrix dominated resource and the sandstones which comprise this production interval are lithic arenites of very fine to medium grain size, generally well sorted and composed of detrital quartz, feldspar and a variety of lithic clasts. Calcite is a common detrital component as well as a cementing agent; quartz cement occurs in minor quantities. Total phyllosilicate contents range from 1-15 weight percent, with most of this being illite and chlorite. Analysis of the clay fractions under 2 microns in size reveals that expandable clay is present interlayered with illite (and possibly chlorite); the abundance is sufficiently low; however, that expandable clay was not readily detected in the bulk rock analyses[5].

The cores used for testing ranged in depth from 5500 to 5560 feet and this zone has been characterized as moderately productive with primary production slightly above and below this interval. Mineralogically this interval differs from the other production zones by poorer sorting and a slightly

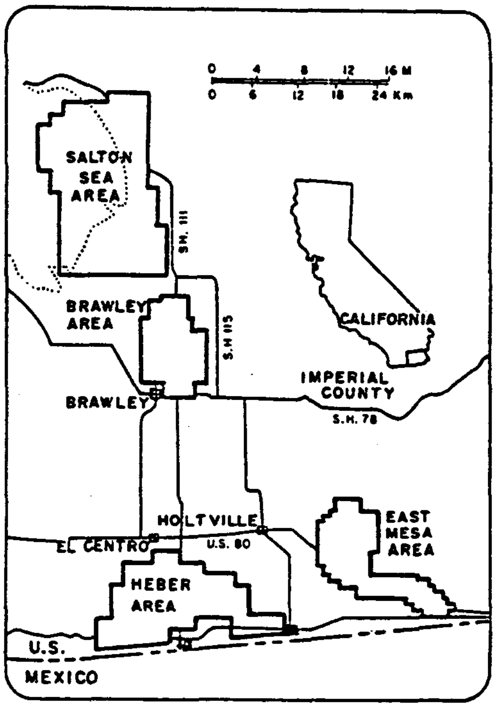


Figure 1. KGRA's of Imperial Valley, California.

higher mixed layer clay percentage. A mineralogical and physical properties [5] analysis based on counting 400 points in each thin section is contained in Table 1.

Table 1

East Mesa Mineralogical & Physical Properties

Sample Depth	Quartz	Plagio-clase	Alkali	Mica	Illite	1 Mixed Layer	Chlor-ite	Cal-cite	Mean Grain Size (mm)	Measured Porosity (Vol 5%)
5505	63.4	6.0	11.5	--	5.4	4.9	4.4	4.3	0.12	15
5506	75.8	5.4	10.4	--	--	--	2.7	5.8	0.09	14
5515	76.9	8.8	10.7	--	--	--	1.2	3.5	0.20	17
5522	70.2	8.2	12.4	--	3.7	--	3.0	2.5	0.13	18
5528	75.5	5.9	9.2	--	3.8	--	3.1	2.6	0.13	23
5531	71.0	8.1	8.6	--	4.0	--	5.5	2.7	0.15	20
5560	60.4	7.8	15.3	--	5.8	7.1	2.1	1.5	0.09	--

Initial permeabilities in the 5500 foot section of between 0.05 to 20 millidarcies have been measured at simulated in situ conditions. Total porosities range from 14 to 25%. Pore size and distribution, shown in Figure 2, have been determined in a representative sample by mercury invasion at pressures up to 30,000 psi.

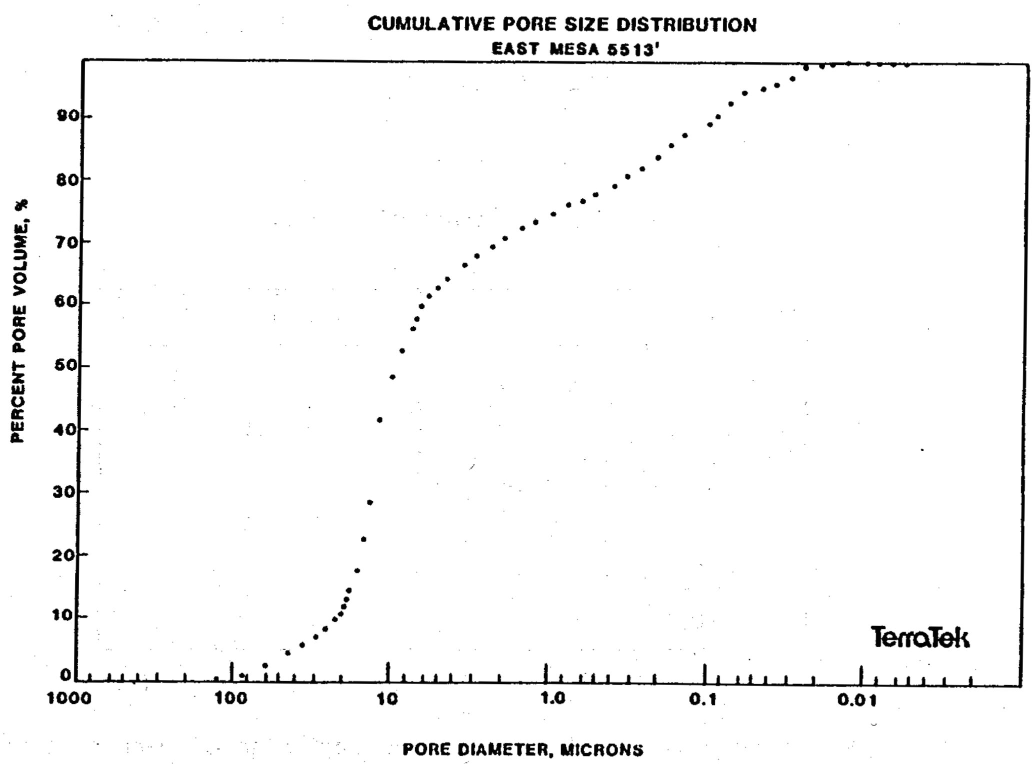


Figure 2. Cumulative Pore Size Distribution in East Mesa Sandstone.

Generic Sandstone

The examination of the generic sandstone by petrographic analysis of thin sections indicates the core used for particle size testing is composed of fairly well-sorted elastic grains of quartz about 0.4 mm in size, sub-angular to sub-rounded in shape[6]. Minor amounts of microcline/orthoclase, plagio-clase, mica and lithic fragments of chert and silicic volcanics are also present in this core material. Several authigenic minerals which occur interstitially include kaolinite, calcite, sericite, limonite and possibly zeolite. Also present on portions of quartz grains which project into pore spaces are overgrowth rims of inclusion free, optically continuous quartz up to 0.02 mm in thickness. No bedding features or other inhomogeneities are visible in the thin section. Listed in Table 2 are the minerals present in the generic sandstone and their approximate percentages.

Table 2

Generic Sandstone Mineralogy

Minerals	Percentage of Core
Quartz	60
Chert	5
Kaolinite	5
Calcite	3
Microcline/Orthoclase	2
Sericite	2
Volcanic Clasts	2
Limonite	1
Muscovite	0.5
Porosity	20

Initial permeabilities measured at the beginning of each particle size test indicate that sample permeability is in the 400 to 600 millidarcy range when at simulated in situ conditions. Total porosity is approximately 20 percent as determined by impregnation of the rock matrix with blue epoxy and examination by petrographic microscope. Pore size and distribution, as determined by mercury intrusion, is shown in Figure 3.

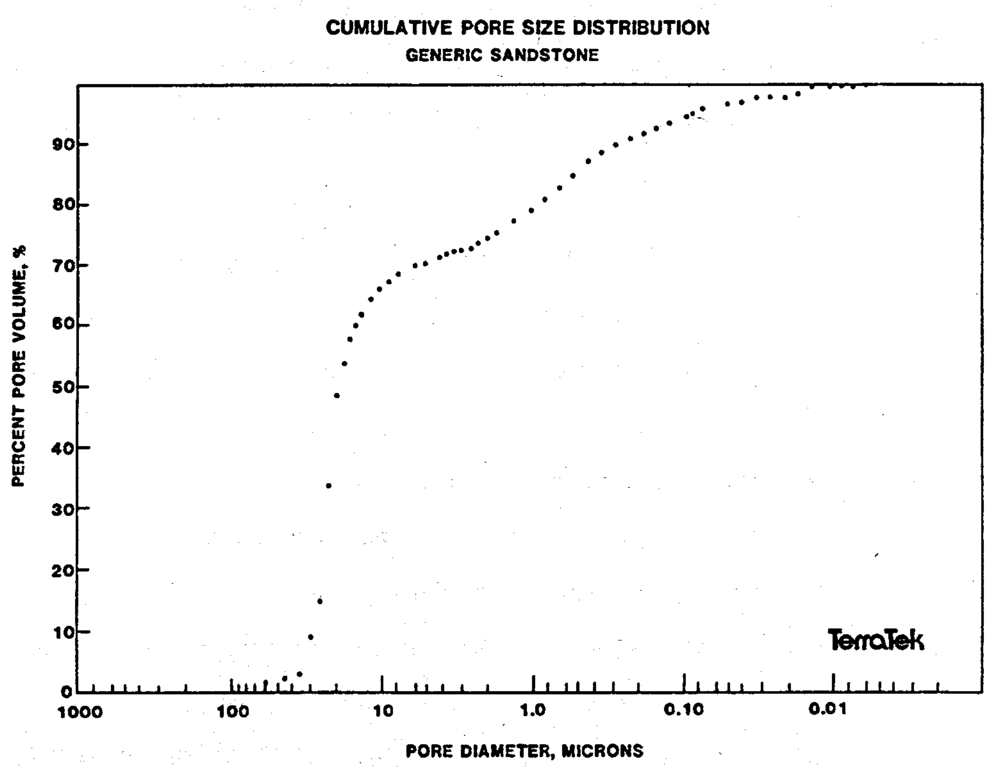


Figure 3. Cumulative Pore Size Distribution in a Generic Sandstone.

FILTRATE CHEMISTRY SENSITIVITY

This section contains three sub-sections. The first describes sample preparation and jacketing methods. Section two will describe test procedures. The third will discuss the results of testing filtrate solutions of KCl, $CaCl_2$, NaCl and deionized water at simulated in situ geothermal conditions.

Sample Preparation

Cores were selected from the most lithologically homogeneous sections of the RGI well 78-30, depths 5500.0' to 5503.1', 5505.2', 5511.0' and 5513.4'. Samples were cored parallel to bedding with sample diameters of 2 inches (5.08 cm) and lengths of 1.3 inches (3.3 cm). All samples were cored with air to minimize pre-test damage due to coring fluids.

Jacketing of test samples consisted of positioning the rock between two stainless steel endcaps to which pore fluid lines were attached. Radially notched dispersion disks were used to insure uniform contact of pore and filtrate solutions at both ends of the cylindrical test sample. The assembled sample was then jacketed with a silicone rubber and a heat shrink teflon (with lockwires tightened about both endcaps) to insure that the sample remained isolated from the fluid applying confining pressure.

Test Procedures

Prior to the start of every test, new pore fluid filters were placed in the pore fluid line. Filtering was performed by two filters in series. The primary filter screened out particles down to 0.9 microns in size with an efficiency of 99.9999%. The secondary filter removes materials as small as 0.3 microns in size with the same efficiency as the primary filter.

When assembly of the test configuration was completed, pore pressure was increased by means of the high pressure nitrogen reservoir and precision gas regulators to a value slightly lower than the confining pressure. The two pressures were then increased incrementally, keeping the confining pressure higher than the pore pressure. This technique minimized the possibility of over-stressing the rock from large increases in effective stress (difference between confining and pore pressure). After the desired 2000 psi pore pressure was achieved, the confining pressure was set at the desired level of 5000 psi.

At this point a pore fluid pressure differential was applied across the sample. When the required differential was achieved the regulators were valved off from the large reservoir tanks, which were allowed to stabilize at pressure. If the test parameters required an increased temperature, as the majority did, the heater was activated. The sample temperature was increased at 0.5°C per minute until the desired level was obtained. The temperature was allowed to stabilize for 30 minutes or more. After all parameters were stable, flow was initiated.

Exposure to a solution of synthetic East Mesa Brine, with the composition as given in Table 3, comprised the first phase of the filtrate chemistry tests. This pore fluid, a 2200 ppm brine, was formulated in the laboratory according to water quality analysis done by the field operator[8]. The brine was allowed to flow until the permeability reached steady state and when this situation existed, the reservoirs were switched and the filtrate solution was introduced into the system. A bleed valve was used to flush the East Mesa brine from the plumbing, filters, and upstream endcap, using the filtrate solution. The filtrate solution portion of the test also continued until a constant permeability to the filtrate was observed. During the entire test,

Table 3

Pore Fluid Analysis of
East Mesa Brine

HCO_3^-	778.1 ppm
N_a^+	626.0
Ca^{++}	9.0
Cl^-	366.7
SiO_2^-	181.3
K^+	30.0
B^+	2.0
F^-	4.0
$SO_4^=$	164.6
TDS	2163

Courtesy: Don Michaels, Republic Geothermal

vital parameters were monitored and stored in a computer file for later inspection and data reduction.

After flow was terminated, the heating was decreased to allow the sample temperature to drop at the same rate it was increased. When the sample temperature was below 50°C the pore pressure and confining pressure were decreased similarly to the preparatory increases. Once the sample was taken from the vessel and the jacket removed, a post test examination was performed and pertinent characteristics noted. The sample was then stored in the appropriate filtrate solution.

Test Results and Discussion

The most significant effect detected while testing for filtrate chemistry sensitivity was an unexpected decline in permeability with time. On an average for all 16 tests conducted, the permeability declined 23% during the pore fluid phase of testing. (To compensate for this dynamic permeability situation, all tests were continued until an equilibrium permeability was established before starting the flow of the filtrate solution.) The mechanisms involved in this phenomena will be addressed more fully in the section on long term permeability tests.

Results from tests with various filtrate solutions are summarized below. Core response to individual filtrate solutions at the four specified temperatures are detailed in the accompanying figures.

Deionized Water: There was a moderate to severe sensitivity of East Mesa core to deionized water as evidenced by an average 36% reduction in permeability. As shown in Figure 4, the stabilized permeability (to East Mesa Brine) and the final permeability, after flow of the filtrate, have resulted in declines ranging from 5% to 75%. Core behavior to a filtrate of deionized water does not appear to be temperature dependent.

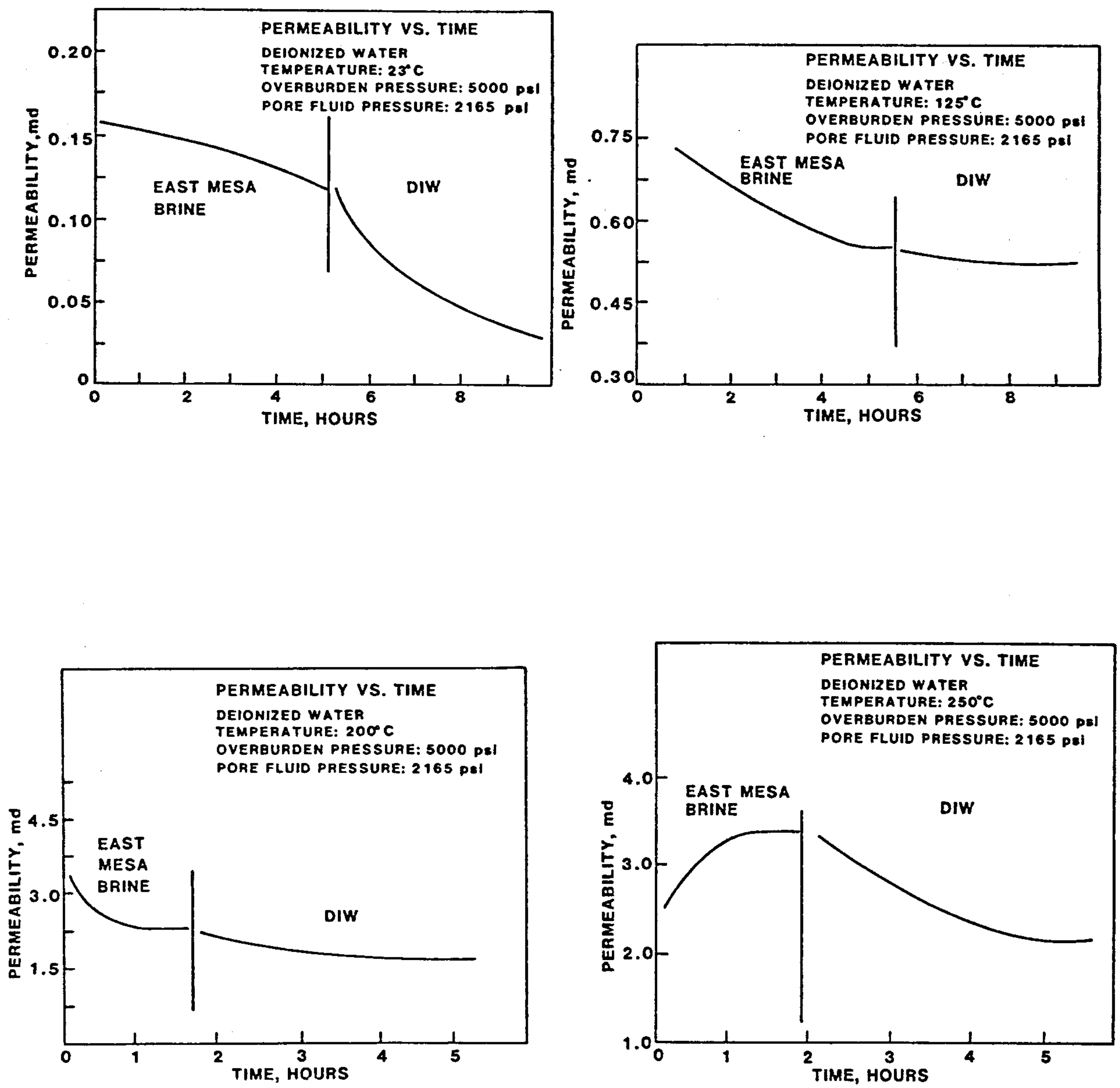


Figure 4. Filtrate Chemistry Sensitivity: Deionized Water Effects at 23°C, 125°C, 200°C and 250°C.

Calcium Chloride: East Mesa core responded with the least damage to a filtrate solution of 3% $CaCl_2$. Two of the four tests conducted resulted in improvements in permeability, one had a permeability decline, and one had no decline. The degree of improvement in two of these tests was significant - 23% and 32% and the results of testing are shown in Figure 5. There does not appear to be a link between core sensitivity to filtrate and temperature.

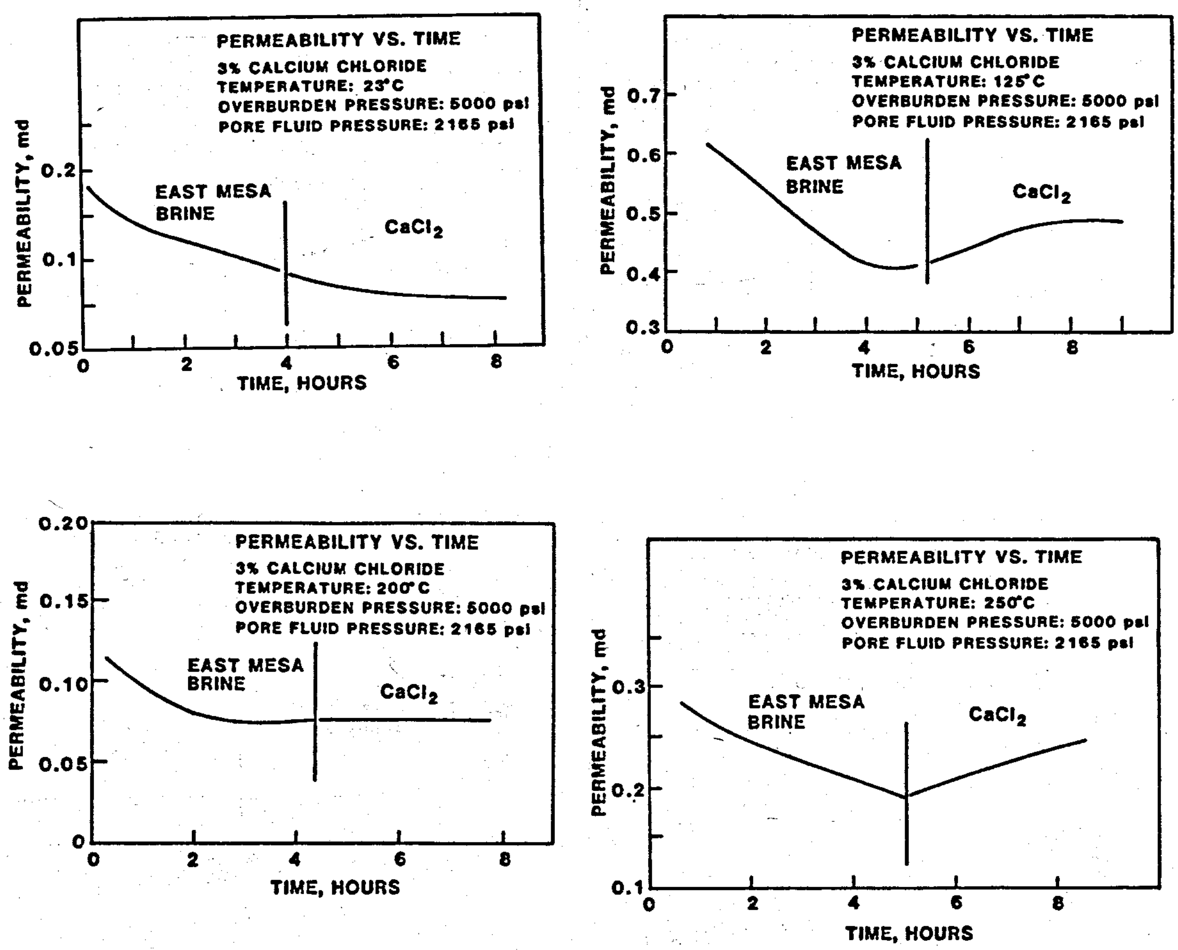


Figure 5. Filtrate Chemistry Sensitivity: 3% Calcium Chloride Effects at 23°C, 125°C, 200°C and 250°C.

Potassium Chloride: The filtrate solution exhibiting the most negative effect on the East Mesa core permeability was KCl, shown in Figure 6. Overall declines in permeability averaged 44% for four tests; one test had a decrease in permeability from 1.99 md to near zero - the only test of all sixteen which had permeability drop that low. As observed in the other filtrate test series, there is no effect of temperature on the degree of core sensitivity.

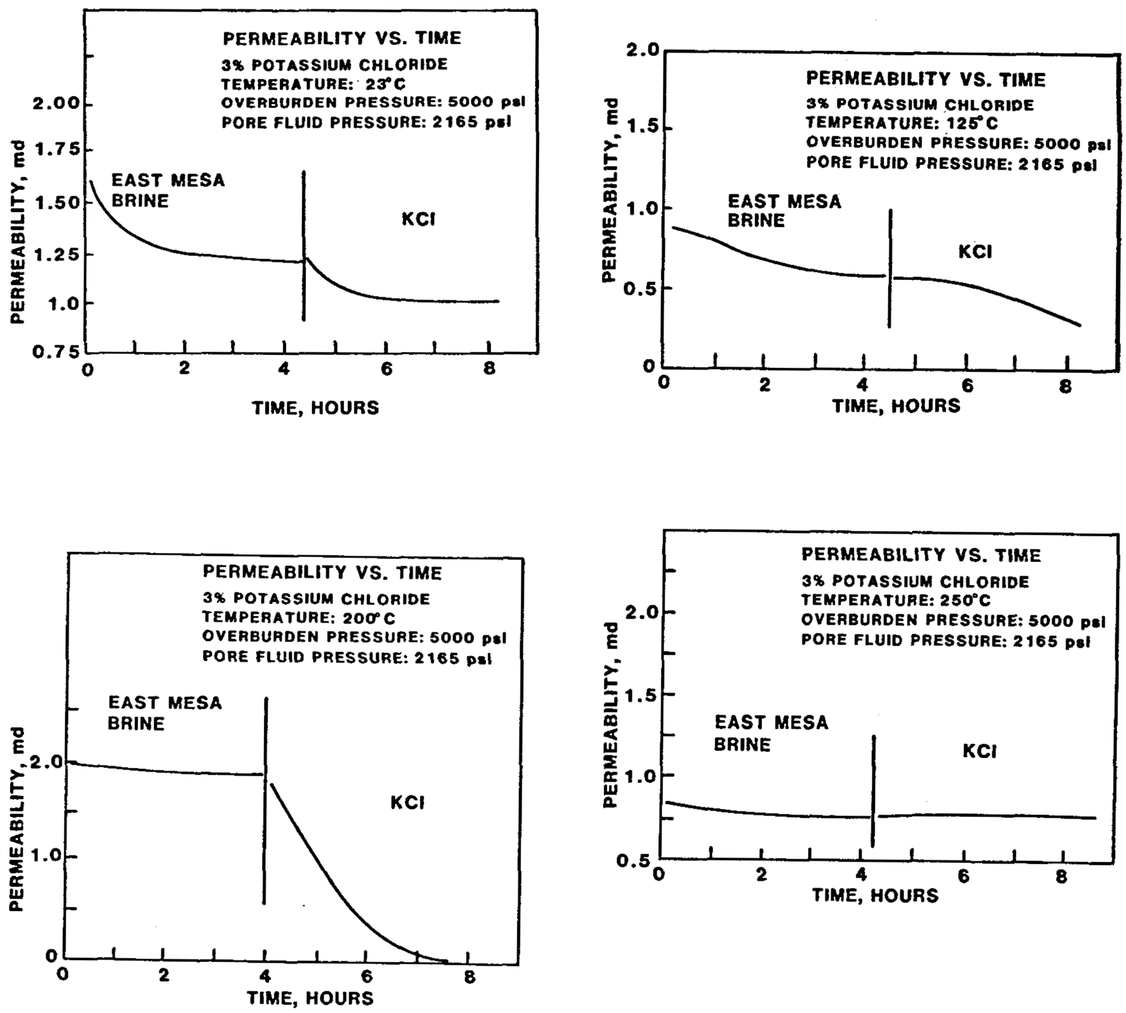


Figure 6. Filtrate Chemistry Sensitivity: 3% Potassium Chloride Effects at 23°C, 125°C, 200°C and 250°C.

Sodium Chloride: Declines in permeability of 18% and 16% were recorded in the tests at 23°C and 125°C while the tests conducted at 200°C and 250°C resulted in no change of permeability. This filtrate solution had the second best performance of the four filtrates in terms of net behavior as shown in Figure 7; nevertheless, its overall performance must be characterized as slightly damaging to core permeability. Temperature does not appear to be a factor in core sensitivity to filtrate.

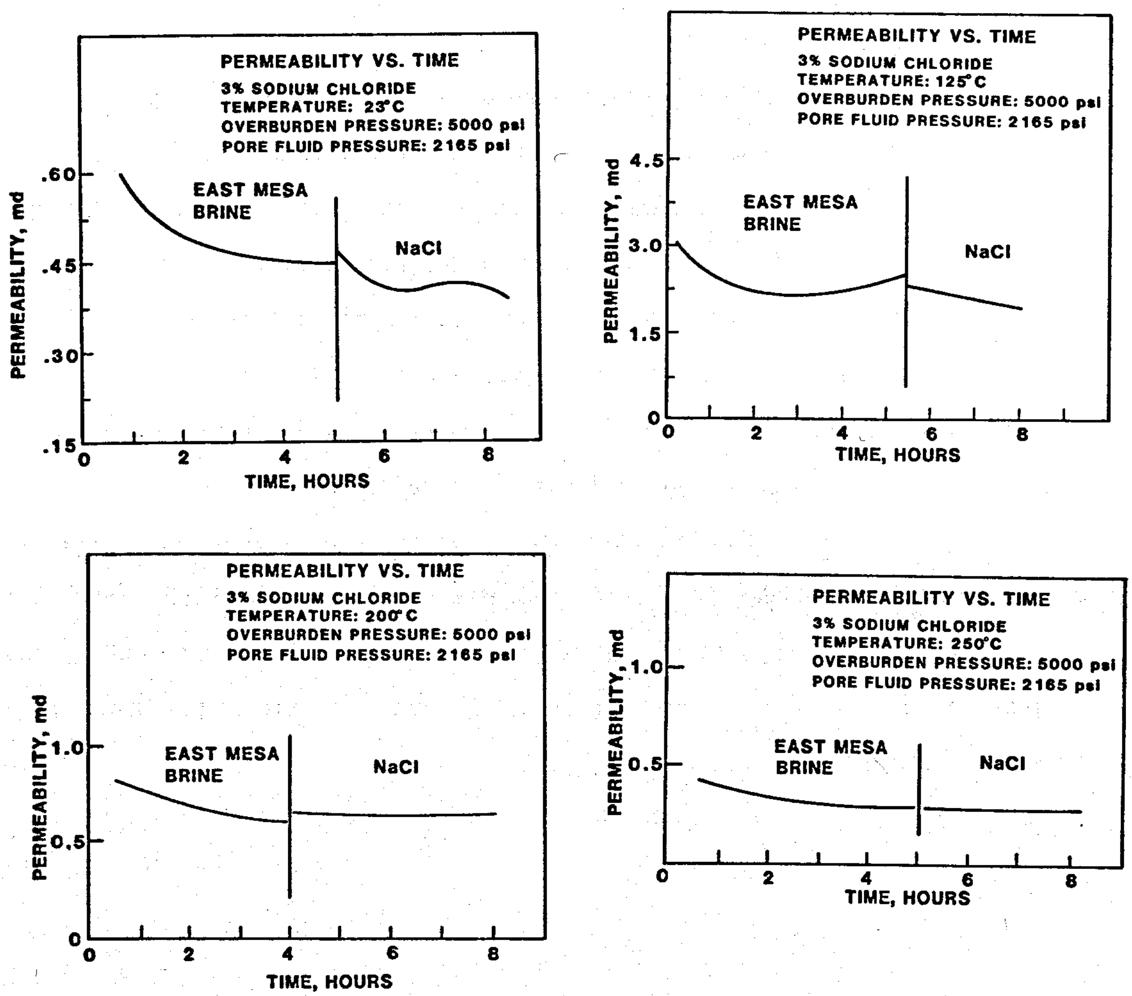


Figure 7. Filtrate Chemistry Sensitivity: 3% Sodium Chloride Effects at 23°C, 125°C, 200°C and 250°C.

Conclusions

Efforts to determine the impact of various mud filtrate solutions on rock permeability have yielded information on core sensitivity. Utilizing actual geothermal reservoir material from the East Mesa KGRA allowed the identification of a calcium chloride filtrate solution as the least damaging to permeability. The use of potassium chloride and sodium chloride caused permeability damage as compared to calcium chloride. These results have impact on the design of field procedures.

One general consideration which should be addressed is the applicability of these findings to reservoir materials which are mineralogically different from East Mesa. The complex chemistry of clays, and even variability of clays within the same production interval, makes it difficult to apply these results on a general basis to all geothermal resources. Generic core material, while helpful in some studies, is not useful where one is attempting to discern a chemical sensitivity. The interaction between a rock and filtrate solution is a unique condition which is not easily transferred to other rock types.

It is recommended that extensive coring of the first few wells drilled in a field be done in order to provide adequate material with which a thorough characterization of the resource can be made. Based on this, selection and evaluation of drilling fluids and their filtrate solutions can proceed at greatest efficiency.

LONG TERM PERMEABILITY TESTING

Sample Preparation and Jacketing

Test samples were cylinders 2 inches in diameter and 4 inches in length located between two stainless steel end caps to which pore fluid lines were connected. Test samples were jacketed using layers of heat shrink teflon tube and silicone rubber (RTV). This prevented flow along the sides of the sample and isolated the internal pore fluid from the confining fluid.

Test Procedures

The sample was placed within the pressure vessel, and heating to test temperature was accomplished by an internal heater with ceramic shrouds to control heat loss. The sample was fully instrumented to provide relevant temperature data. Pore fluid flow lines were attached to the sample; these pore fluid lines have two colloidal filtering systems plumbed in which remove 99.9999% of the particles down to 0.3 microns. Within the flow cart are the pore fluid accumulators which were used to generate pore pressure. Piston displacement within these accumulators was monitored electronically to within 0.1 percent providing a continous record of fluid movement within the system. Pressure was generated by using a high pressure nitrogen system designed to provide stable long-term pressure.

Test Parameters

The sandstone core samples used in this testing were also from the 5500 foot zone of Republic Geothermal Well 78-30RD, East Mesa Known Geothermal Resource Area (KGRA), Imperial Valley, California. All testing done in this study was conducted at the following simulated *in situ* conditions:

Confining Pressure, Cp = 6000 psi

Pore Fluid Pressure, Pp = 2400 psi

Temperature, T = 302°F

Pore fluid used in testing was the East Mesa simulated brine described earlier in this report.

Test Results

Previous Terra Tek tests on this material, carried out prior to this particular investigation, indicated unexpected decreases in permeability during the flow of synthetic East Mesa brine through samples of East Mesa sandstone. It must be emphasized that sensitivity to low salinity (2200 ppm) brines was not originally envisioned in this formation since conventional formation sensitivity indicators were either absent or neutralized. The very small amounts of swelling montmorillonite clays, and the exposure of existing formation clays to the elevated geothermal temperatures was thought to be sufficient to alter these clays to a non-water sensitive structure.

It was initially suspected that a system-induced error was responsible for the decrease in permeability. As recently suggested by Potter et al[9], oxidation/corrosion of the stainless steel in the test system may produce a colloidal ferric ion which impairs permeability by precipitate plugging. To find the source of any such error, extensive checks of the entire flow system were made. The two colloid filtering systems were examined for the presence of artificially induced iron-bearing particles and operating procedures were carefully scrutinized. Little or nothing was found. Further permeability tests of this material on other systems, and tests of this systems' ability to confirm permeability measurements made elsewhere, eliminated suspicions of any large error caused by interaction of the brine and stainless steel.

To test for formation sensitivity to formation brines, a test was devised in which a 3 percent potassium chloride solution was flowed through a test sample for a period of 26 hours, followed by a flow of East Mesa brine (see Figure 8). Note that the introduction of the simulated pore fluid resulted in a further, more severe impairment over the course of the next 10 hours before stabilizing at a value 70 percent below the stable KCl permeability. The reduction in permeability in this portion of the test could be attributed strictly to "salinity contrast", which is flow of low salinity fluid following a fluid of higher salinity (as documented by many researchers including Gray and Rex (1966)[7] and Jones (1964)[3].) Reinitiation of flow with KCl ninety hours into the test resulted in a very slight increase in permeability. It must be concluded that once the matrix has been damaged by exposure to a low salinity brine, subsequent treatments with high salinity brines produce little or no improvement in permeability.

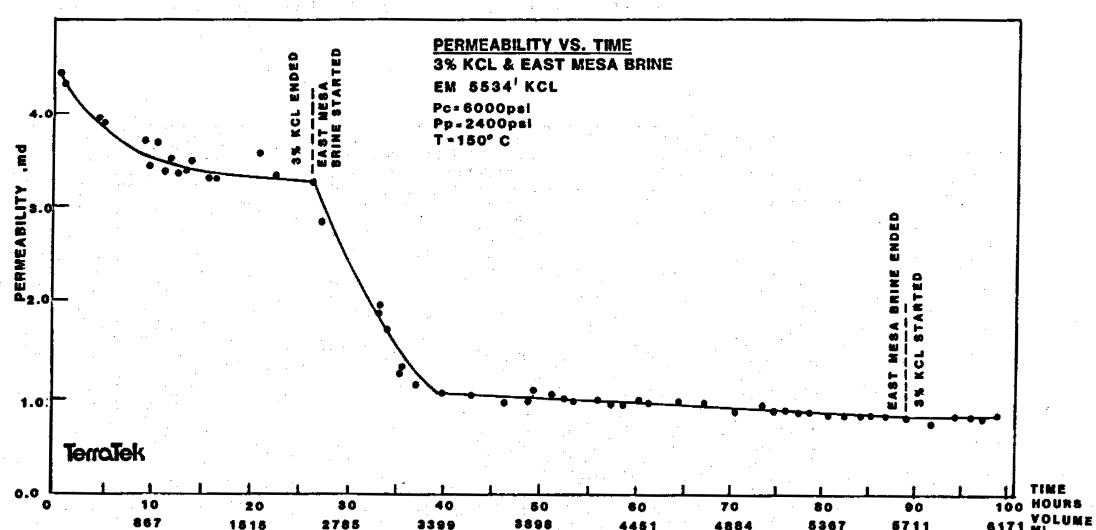


Figure 8. KCl/East Mesa Brine Test Results.

Identification of mechanisms responsible for damage was done by conducting a series of long term permeability tests using only East Mesa brine. The capability to duplicate overburden stress, pore fluid pressure, and the reservoir temperature which exists in the resource, using actual production zone core samples, allowed the examination of a number of different variables which may be contributing factors to formation damage. Test evidence suggests interstitial fines and chemical alteration of clays contribute equally to formation damage.

Interstitial Fines: The next test in the series, East Mesa 5513', lasted seven days and consisted of two shut-in periods (no flow) and one flow reversal. The shut-in periods, 3 and 8 hours in duration, were intended to duplicate field drilling conditions (such as downtime or a bit run) and allow an evaluation of the effects on formation permeability. As can be seen in Figure 9, both shut-in periods are characterized by initially higher permeabilities which level off rather quickly to a new, slightly higher permeability.

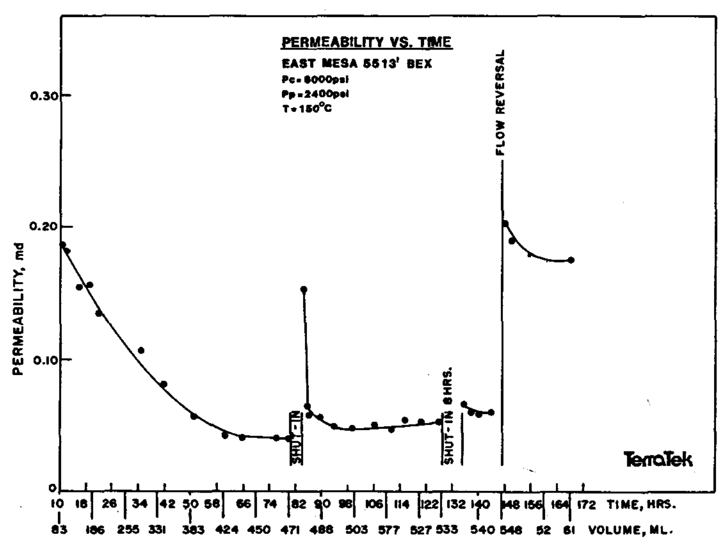


Figure 9. East Mesa 5513' Test Results.

A flow reversal, 148 hours into this test, was to test the theory that permeability impairment was due to a reversible mechanical process, like migration of fines, rather than restriction of flow due to clay hydration. Dramatic improvement in permeability which resulted appears to support the theory of damage by migration of interstitial fines to the pore throats. Confirmation of this was obtained by doing injection of mercury, under 30,000 psi pressure, into two samples; one was the tested sample from 5513 ft. and the other was a virgin piece removed immediately adjacent to the cored, tested sample. The results, shown in Figure 10, show the distribution and size of the pore throats in the tested and untested core samples. Obviously there has been a significant decrease in size, on the order of 40%, in the majority of pore throats.

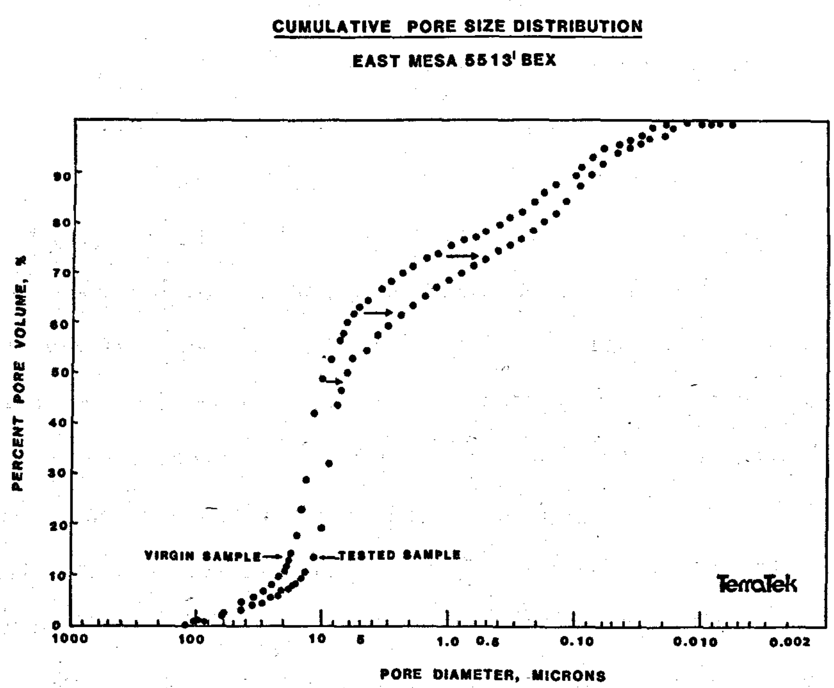


Figure 10. Pore Size and Distribution in East Mesa 5513'.

Further evidence to support migration of interstitial fines comes from thin section analysis of a second tested sample from 5513 feet. Samples from the fluid in-flow and out-flow ends of the damaged core were removed and were prepared into thin sections for petrographic analysis to determine the materials contributing to formation damage. The thin sections were quantitatively examined using an automatic stage and point counter to determine mineralogy and physical properties. A minimum of 600 points was counted in each area of interest. The porosity in the damaged sample was decreased from 6.9% at the in-flow face to 4.7% near the sample out-flow face. The changes are statistically significant at the 95% confidence level. While petrographic analysis cannot resolve the actual constituent causing porosity decrease due to its small size, naturally occurring fines -- both clay and felsic minerals -- are indicated.

Chemical Effects: East Mesa 5533' test, Figure 11, was conducted to assess if chemical mechanisms such as swelling of formation clays were a factor in damaging the matrix permeability. This test consisted of a 2½ hour initial permeability measurement followed by a four day eighteen hour period of no flow. The purpose was to determine what reaction the core would have to prolonged static exposure to the East Mesa brine. Clearly the result is a decrease in permeability from a pre-shut-in value of 8.5 millidarcies to less than 1 millidarcy when flow was restarted. Flow reversals twelve and eighteen hours after the nearly five day shut-in period resulted in substantial improvements in permeability to 2 and 3 millidarcies, respectively.

In an effort to better understand the chemical mechanisms occurring in the reservoir rock, extensive chemical analyses were conducted on effluent samples from the second East Mesa sample from 5513'. This test was selected because it exhibited the typical rapid decline in permeability, had no shut-in

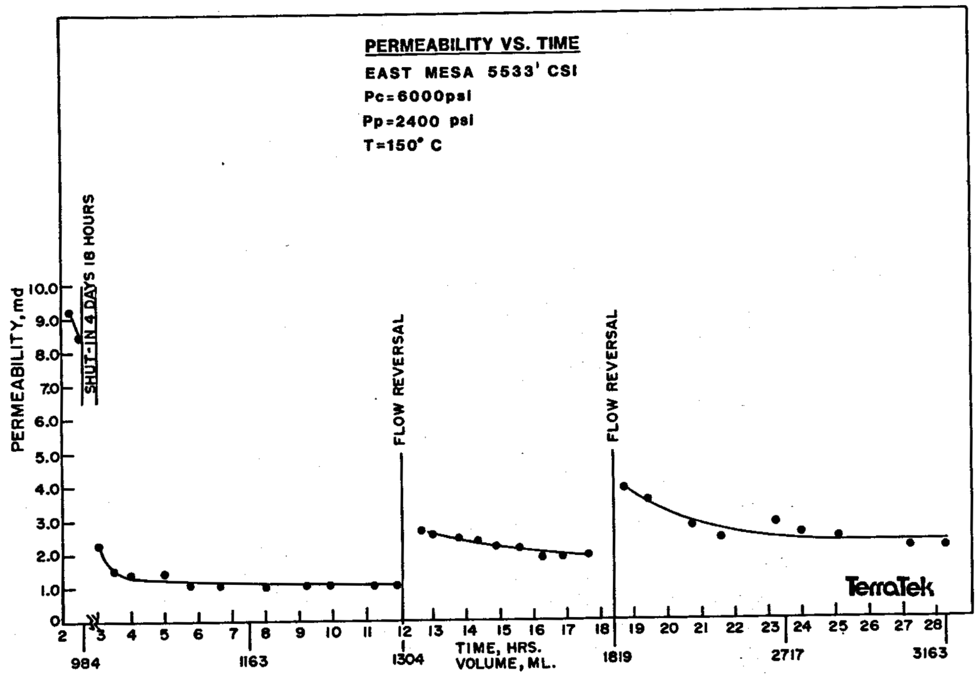
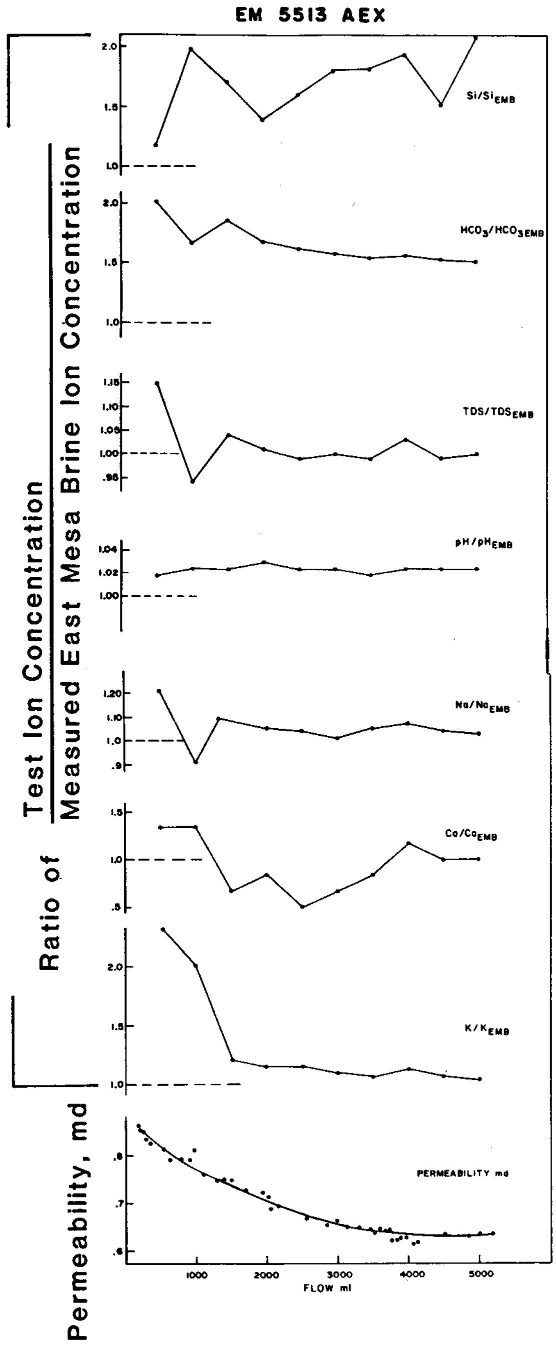


Figure 11. East Mesa 5533' Test Results.

periods or flow reversals, and frequent samples were taken of the brine which had passed through the core. Samples collected during this test were coffee-colored solutions which were analyzed by emission spectrometer for elemental concentrations, total dissolved solids (TDS), carbonates and pH. Results are shown in Figure 12. It is interesting to note that during the first 1500 milliliters of effluent, the most severe decline in permeability corresponds with large changes in the concentrations of the individual elements. Correlation between the stabilization of the elemental concentrations and a steady-state permeability is indicated.

Discussion of Results

Test results confirm that particle migration and clay hydration are two mechanisms of damage which impair the permeability of the East Mesa sandstone reservoir rock. Observations made during testing indicate that these mechan-



P_c = 6000 psi
P_p = 2400 psi
T = 150° C
ΔP= 60 psi

Figure 12. Effluent Chemistry Analysis.

isms are operating even though a pore fluid of similar chemistry and concentration to the formation fluid was used. Post-test analyses by petrographic microscope, mercury injection of the core, and effluent sampling provide strong supporting evidence that the pore system of this rock is being dramatically altered by these mechanisms.

Flow reversals during the long-term permeability tests from 5513' and 5533' indicate there are interstitial fines which migrate downstream to a pore throat and bridge across. The progressive degradation in permeability is probably due to greater numbers of fines accumulating at these restrictions in the pore system. Mercury injection confirmed significant changes have occurred in the sizes of the pore throats. Following shut-in periods of both tests permeability spikes occur which probably result from the sloughing of particles from the vicinity of the pore throats. This sloughing is caused by the decreased dynamic fluid pressure during shut-in which releases particles from the pore throat, thus the pore throat clears. The flow is unimpeded when started again because the throat is now clear, but very soon the particle obstructions again build up and permeability returns to lower, near-previous levels.

The sources of released interstitial fines are likely the loosening of matrix cement as a result of dissolution of carbonates and the mechanical breakdown of the more fragile clay structures. Figure 12 also shows evidence of carbonate extraction coincident with decrease in permeability. This phenomenon was also observed by Reed (1976)[10] who concluded that removal of the carbonate cement would free particles to migrate. It is probable that this mechanism contributes interstitial fines which act with clay particles to clog pore throats.

In addition to removal of elemental calcium, it is significant to note that there are initial peaks of potassium and sodium ions, and subsequent leveling out, all at concentrations well above the East Mesa brine background. It is suspected that the damage mechanism here is alteration of the clay structure by ionic exchange or depletion. Effluent samples taken during the long-term permeability test with East Mesa brine show that substantial quantities of potassium are being removed during early portions of the test. Reed (1976)[10] has shown that when micas are exposed to salt solutions devoid of potassium ions, potassium is extracted from the mica causing an alteration to an expanded structure consisting of numerous frayed edges. It is possible that some sodium-potassium exchange is taking place which would contribute to altered, less water stable clay structures. In any case, the abundance of potassium removed is evidence of a progressive alteration of mineralogical structure.

The clay structure, once altered, is very fragile and is easily damaged by the shear forces of fluid flow. Gray and Rex noted similar particle migration effects which they attributed to changes in the double layer thickness of layered clays; this weakens the structure through localized bending moments at the edges of clay particles. Though the clays most mobile in their studies were kaolinite and slightly mixed layer micas, vermiculites and very chloritic mixed layer clays also exhibited mobility. (Note the presence of illites and chlorites in the analysis of East Mesa sandstone in Table 1.)

Conclusions

Formation damage, when flowing the synthetic pore fluid through a matrix permeability resource, can impact formation productivity quite significantly. Test results on core samples from East Mesa KGRA indicate the following conclusions:

1. The permeability of East Mesa sandstone is significantly affected by the flow of the synthetic pore fluid of approximately 2200 ppm, TDS. Permeability reductions of up to 75% are common.

2. Pore fluid alteration of formation clays to a structurally expanded and weakened frayed edge condition allows the velocity (and shearing effects) of pore fluid flow (as would occur during production) to collapse the fragile clay structure. The clays disperse within the pore fluid and create obstructions at pore throats reducing permeability.

3. Carbonate dissolution (apparent in chemical analysis of effluents) may allow the release of previously cemented interstitial fines. These fines can be transported by the pore fluid and contribute to pore throat blockage.

4. Once the formation matrix has been damaged by exposure to a low salinity brine, subsequent treatments with high salinity fluid produce little or no improvement in permeability.

The results from testing indicate permeability can be severely, irreversibly impaired. Since this process is dependent upon the clays present within the pore space, the equilibrium pore fluid, and possibly velocity, it is difficult to extrapolate this behavior, but similar behavior seems likely in other low salinity, matrix dominated sandstone geothermal reservoirs.

The findings of this study raise several important concerns which must be considered. First, the East Mesa reservoir rock was not thought to be water sensitive. This supposition was based upon rules-of-thumb such as the small quantity of smectite clays, lack of swelling clays in the formation and the alteration of existing formation clays to a stabilized structure by the elevated temperatures associated with the geothermal resource. It may be that for geothermal conditions, we can no longer judge formation behavior by a handful of commonly accepted criteria such as the presence or lack of certain clays. Comprehensive laboratory testing to fully characterize the reservoir rock is necessary if we are to identify and quantify the mechanisms at work within the rock.

Drilling procedures which have had good intentions may, in fact, be determined to be inappropriate had the reservoir rock been fully evaluated.

Formulation of the drilling fluid using the formation brine as the make-up water is one example. In this case, use of the formation pore fluid as the make-up water appears to the operator and service company as the best fluid to use because it is expected to be in equilibrium with the formation. In fact, we have demonstrated a sensitivity of the formation upon exposure to, and flow of, the simulated *in situ* pore fluid. It should be mentioned that the possibility of the synthetic brine formulation not being an exact duplication of the *in situ* brine is very likely. One must remember the accurate sampling of the *in situ* brine is seldome achievable. Variation of brine composition within the production interval and changes of temperature and pressure as the brine travels up the annulus are bound to occur and result in only a representative sample not an exact brine composition. Therefore, use of the pore fluid for drilling fluid formulation has the potential to be a severe damaging mechanism when in reality it was used to minimize damage.

Finally, whether or not the pore fluid is in equilibrium with the formation may not be sufficient in itself to prevent damage. All formations contain some percentage of colloidal-sized particles which, when disturbed by an artificially induced pore fluid flow rate higher than the normal rate, will react by increasing particle concentration in the pore fluid. The increase in pore fluid flow rate as the reservoir is put on production may be sufficient alone to shear interstitial fines - both clay and non clay - from the walls of the pore space. This increased particle concentration will then converge at the pore throats and clog; the result being a decrease in permeability which is unavoidable by any alteration of operating procedures, the drilling mud or other attempts by the operator. What may be needed is a series of laboratory tests to determine the least damaging conditions, but in reality, achieving zero damage may be impossible.

PARTICLE SIZE AND DISTRIBUTION

Sample Preparation and Configuration

Standard coring and jacketing procedures, as described in the section on long-term permeability tests, were employed in evaluating the effects of particle size and distribution on matrix permeability. A generic sandstone material was selected because of its uniform lithology and lack of swelling clays.

The only departure from the previously described test configuration was the substitution of a 3¼" long 1½" diameter cylinder known as the mud chamber for one stainless steel endcap. This chamber and the lower face of the test sample created an interface simulating the wellbore annulus and the formation face. Contents of this chamber can be dynamically agitated by a motor driven stirrer.

Test Procedures

The sample was placed within the pressure vessel and heated to the test temperature by an internal heater with ceramic shrouds to control heat loss. The sample was fully instrumented to provide relevant temperature data. Flow lines were attached to the sample and then interfaced with the mud circulation system. Confining pressure was raised to 5000 psi and pore pressure to 2165 psi in increments not exceeding a total effective stress of 2835 psi. Following the application of confining pressure and pore pressure, the sample temperature was increased at a rate of approximately 0.5°C/min to the desired test temperature. The system was allowed to stabilize for a period of one to two hours. Testing began when all parameters were stabilized.

Initial Permeability: Brine flow was initiated across the sample in the direction of backflow (top of sample to mud chamber) by a gas pressure that was held constant by precision regulators and large reservoirs within the flow cart. Volume change recorded against a time base was used to determine the flow rate through the sample. Flow was allowed to continue for a minimum of one hour or until steady-state was achieved. Permeability was calculated from sample dimensions, fluid flow rates, and differential pressure across the sample, with necessary corrections for elevated temperatures.

Drilling Fluid Filtration: Following the initial permeability measurement, pore pressure was equalized through the sample and the pore fluid occupying the mud chamber was slowly displaced by the particle-laden drilling fluid. Several chamber volumes of drilling fluid were flowed through the mud chamber to ensure that all pore fluid had been displaced.

A pressure differential was then established across the test sample with the pore fluid pressure at 2165 psi and the drilling fluid pressurized approximately 200 psi above this value. This pressure differential and the resulting flow were opposite in direction to the previous permeability measurement and simulated the loss of drilling fluid from the wellbore annulus to the formation when an overbalanced mud condition exists. To simulate downhole circulation and to prevent particle settling, the drilling fluid was dynamically agitated by a motor-driven stirrer located in the mud chamber. Drilling fluid was slowly exchanged through the chamber during this dynamic period, allowing generation of a dynamically stable equilibrium filter cake. This dynamic filtration was continued until steady-state filtrate loss through the sample was experienced. The duration of this filtration varied depending on the permeability of the rock, the test temperature and the drilling fluid being used, but in general lasted about two hours. At this point the dynamic agitation and drilling fluid circulation was terminated, but the differential pressure was maintained. This static filtration phase was continued for approximately six to eight hours. The confining pressure, pore fluid pressure and temperature were kept stabilized at specified levels. Rate of filtrate flow was monitored and recorded for the duration of static filtration.

Final Permeability: Filtration was terminated by equalizing the pore pressures on both ends of the test sample. Drilling fluid was then displaced from the mud chamber by pore fluid. To maintain a realistic simulation, no attempt was made to remove the filter cake formed upon the face of the sample by mechanical or chemical means. Backflow was then initiated in the opposite direction of mud penetration in the same manner that the original permeability test was conducted. Flow was maintained for approximately two hours, during which time the pressure differential across the sample was held constant. Flow data recorded during this period were used to calculate the final permeability which was compared to the virgin value.

Particle Material Description

The material used in testing for particle size effects was aluminum oxide provided by a leading abrasives company. The specific gravity was 3.93 gm/cc and it was irregular and angular in shape, as shown in Figure 13. Aluminum oxide and silicon carbide from several companies were evaluated by scanning electron microscope, x-ray analysis and the Coulter Counter before selecting the material most uniform in size and shape for use in this study.

Drilling Fluid Description

The KCl polymer drilling fluid system used in this testing was formulated by Chromally Delta Mud Co. and has been used by Republic Geothermal, Inc. in East Mesa, California. Preparation of the drilling fluid was done by Terra Tek.

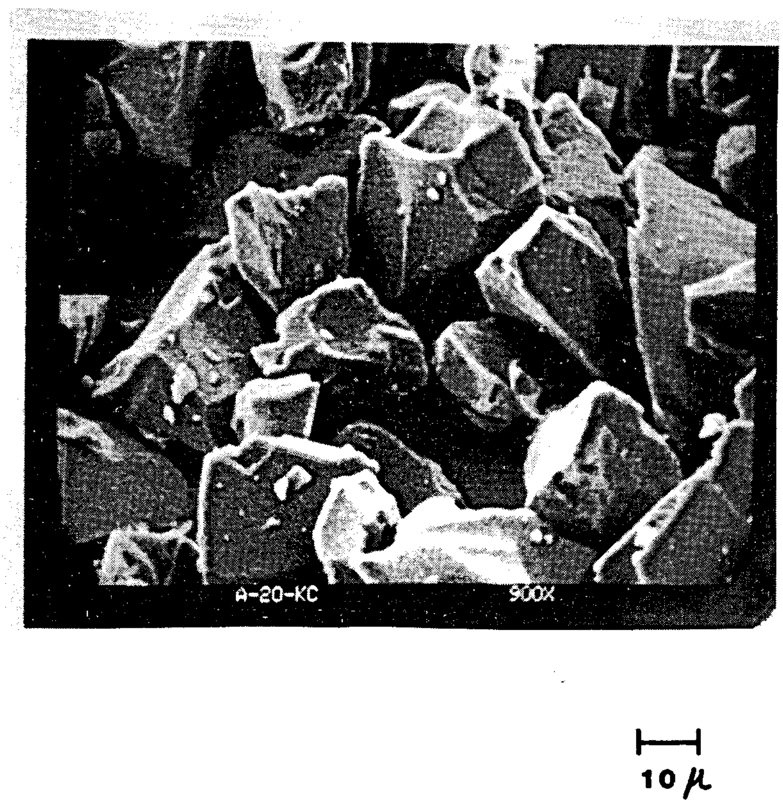


Figure 13. Microphotograph of Aluminum Oxide Particles used in Particle Size Testing.

Formulation of this drilling fluid per standard 42 gallon barrel is as follows:

KCl Polymer

10 lbs.	Potassium Chloride (KCl)
2 lbs.	Del HyVis B (trade name)
0.5 lbs.	Sodium Hydroxide
0.125 lbs.	Sodium Sulfite
0.125 lbs.	Potassium Phosphate Dibasic (K_2HPO_4)

In general, KCl polymer systems range from a clear fluid for maximum rate of penetration to a gelled liquid for maximum hole cleaning properties. Hydroxyethyl cellulose polymer (HEC), marketed under the trade name of Del Hyvis B, acts as a viscosifier and a fluid loss control additive. The temperature limit of this system is approximately 150°C (300°F) but can be extended slightly by the addition of potassium phosphate dibasic (K_2HPO_4) which acts as a temperature stabilizer and buffer. Corrosion control is maintained by the addition of sodium sulfite (oxygen scavenger) and sodium hydroxide (pH control).

Test Results and Discussion

Two variables, particle size and particle distribution, were evaluated as a function of temperature to determine the effects on matrix permeability. Summary of results from this portion of the formation damage study will be discussed below. Individual particle effects on permeability are detailed in Figures 14 through 22.

Particle Size: Three particle sizes - 5μ, 20μ and 50μ - were tested at temperatures of 23°C, 175°C and 250°C while maintaining simulated *in situ* pore and overburden pressures. Individual performance of the three particle sizes in terms of recovered permeability ratio (ratio of final permeability to initial permeability) was quite poor in 6 out of 9 tests. Three tests having some recovered permeability were the 5μ-23°C, 20μ-175°C and 50μ-175°C tests. Table 4 summarizes the recovered permeability ratio of each individual particle test and Figures 14 through 16 display permeability recovery as a function of temperature and time.

Table 4

Recovered Permeability Ratio vs Particle Size as a Function of Temperature for a Generic Sandstone

Particle Size	Temperature		
	23°C	175°C	250°C
5 μ	0.75	0.01	0.03
20 μ	0.07	0.48	0.04
50 μ	0.04	0.16	0.01

Examination of recovered permeability ratio at 23°C reveals a preferential particle bridging size of 5μ; at 175°C both 20μ and 50μ are partially effective in restoring permeability, and at 250°C there were no individual particle sizes that were effective.

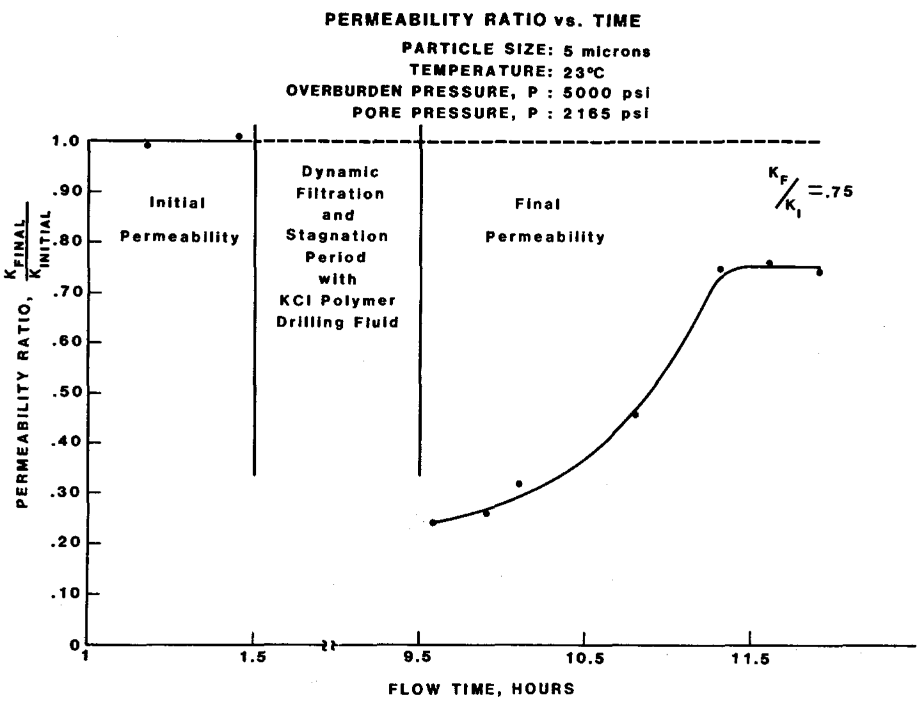


Figure 14. Permeability Recovery at 23°C Using a 5 Micron Sized Particle.

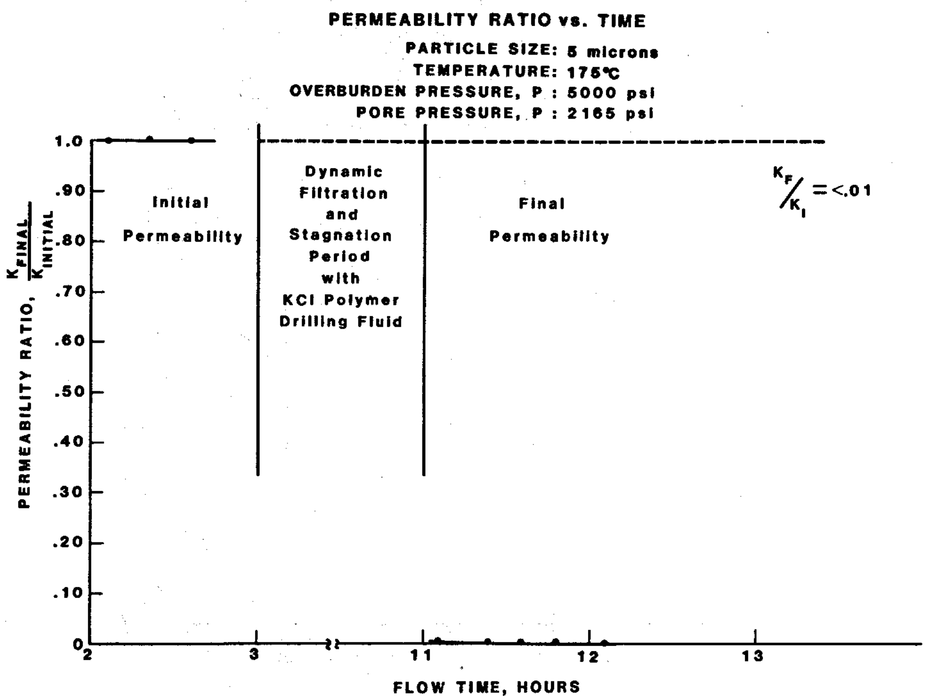


Figure 15. Permeability Recovery at 175°C Using a 5 Micron Sized Particle.

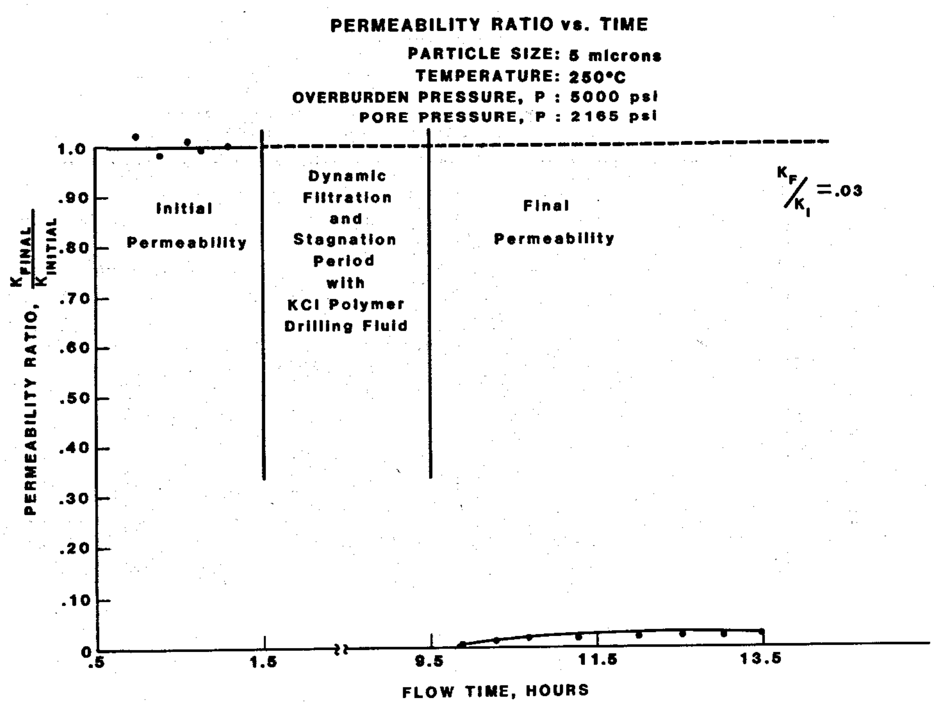


Figure 16. Permeability Recovery at 250°C Using a 5 Micron Sized Particle.

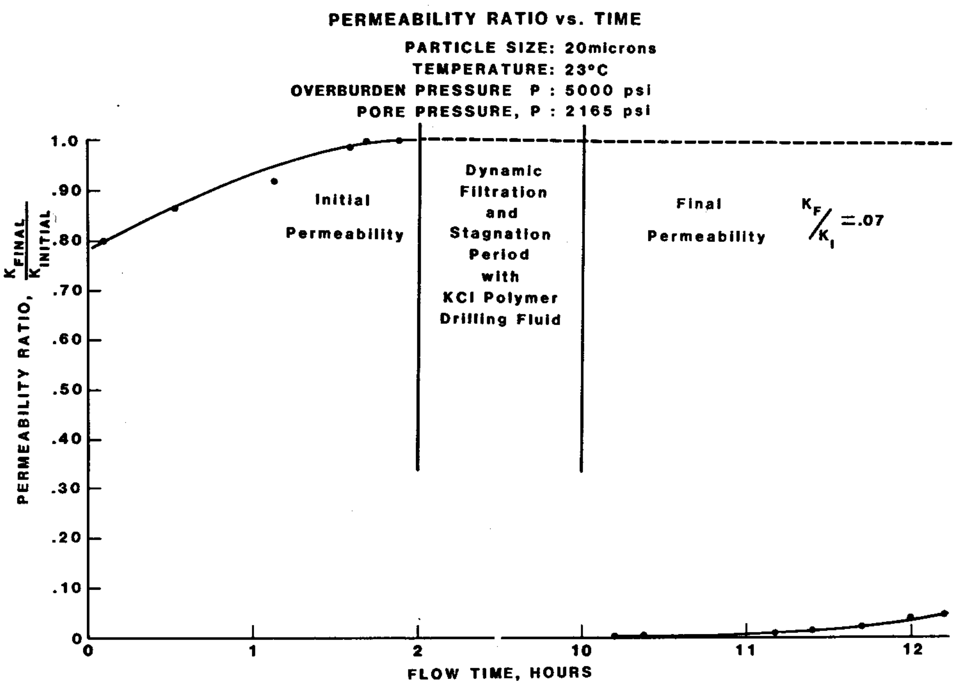


Figure 17. Permeability Recovery at 23°C Using a 20 Micron Sized Particle.

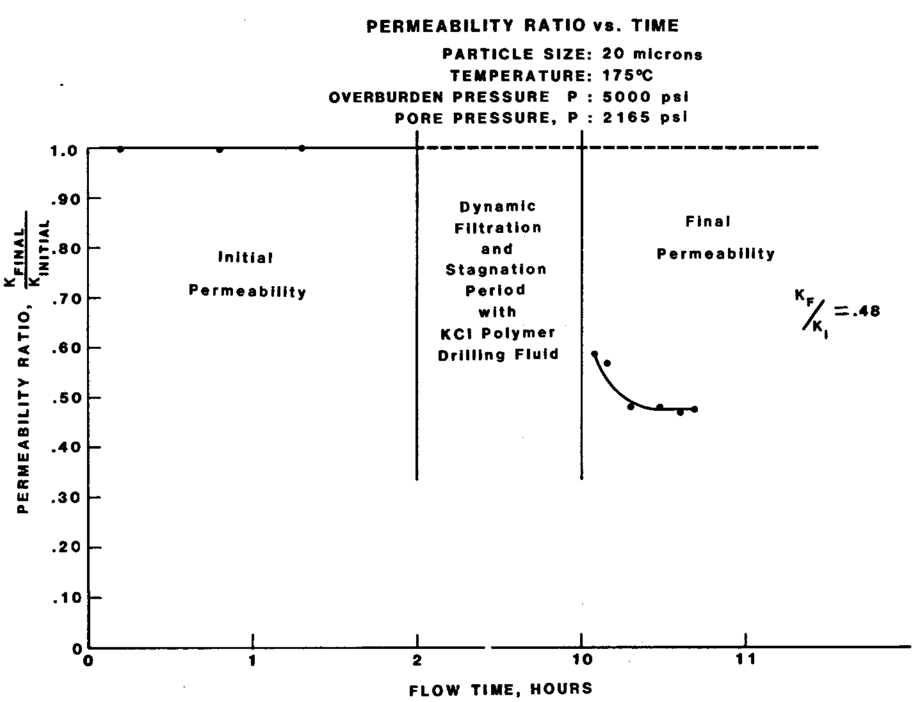


Figure 18. Permeability Recovery at 175°C Using a 20 Micron Sized Particle.

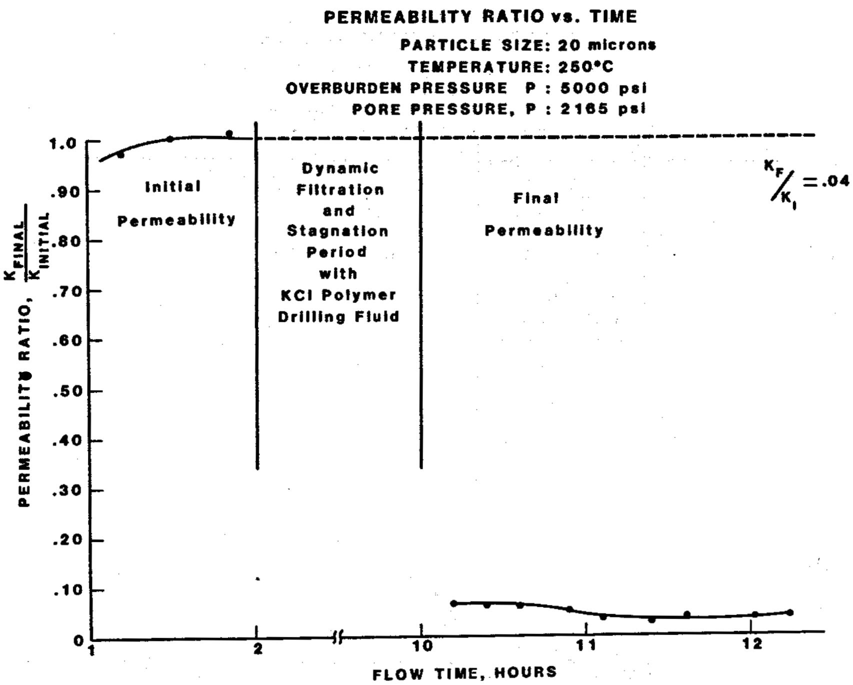


Figure 19. Permeability Recovery at 250°C Using a 20 Micron Sized Particle.

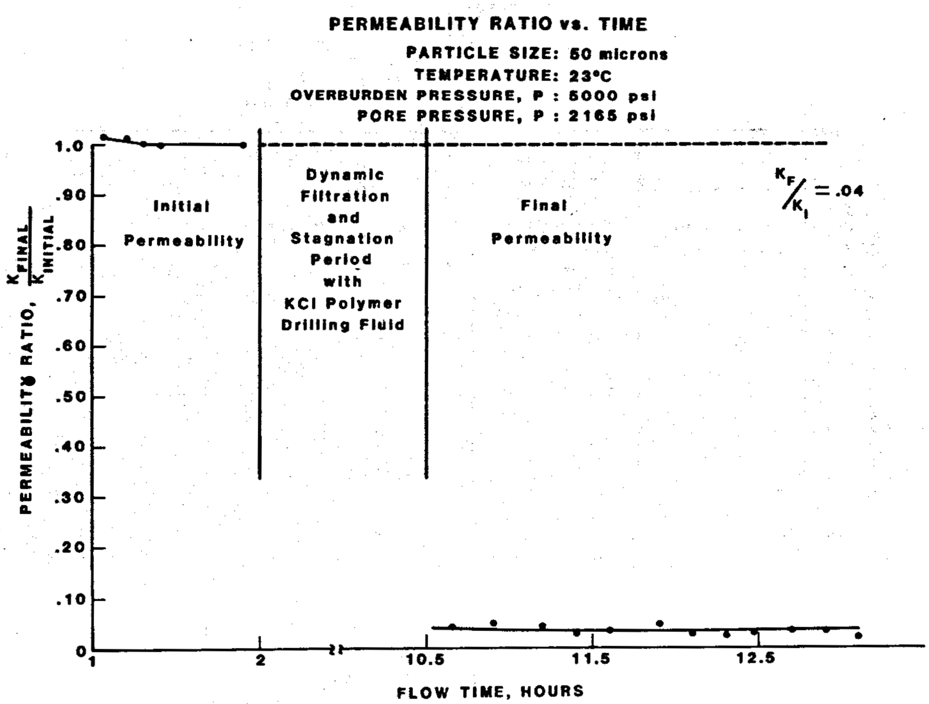


Figure 20. Permeability Recovery at 23°C Using a 50 Micron Sized Particle.

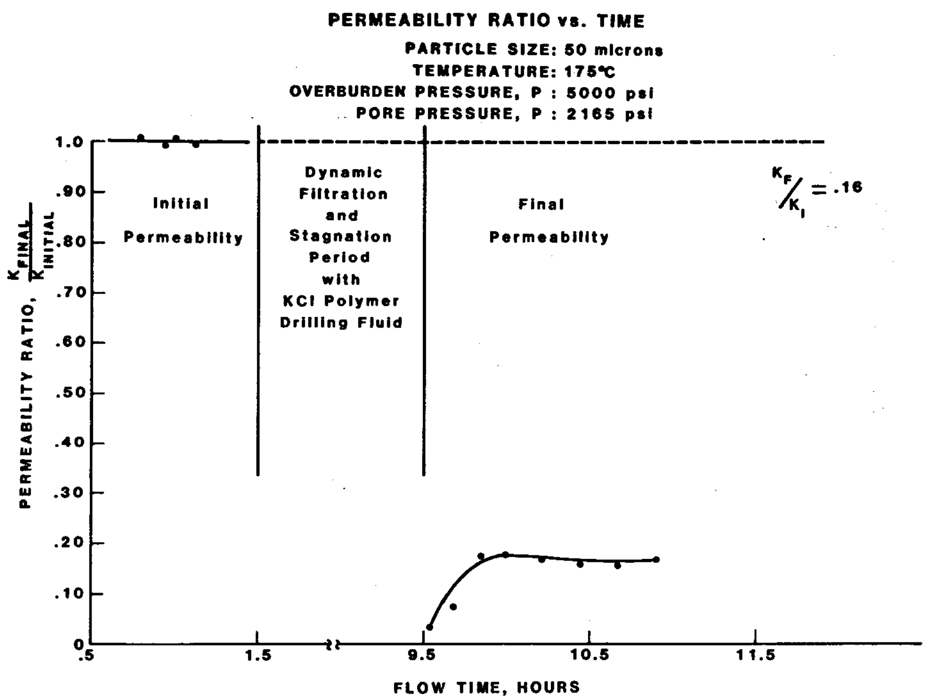


Figure 21. Permeability Recovery at 175°C Using a 50 Micron Sized Particle.

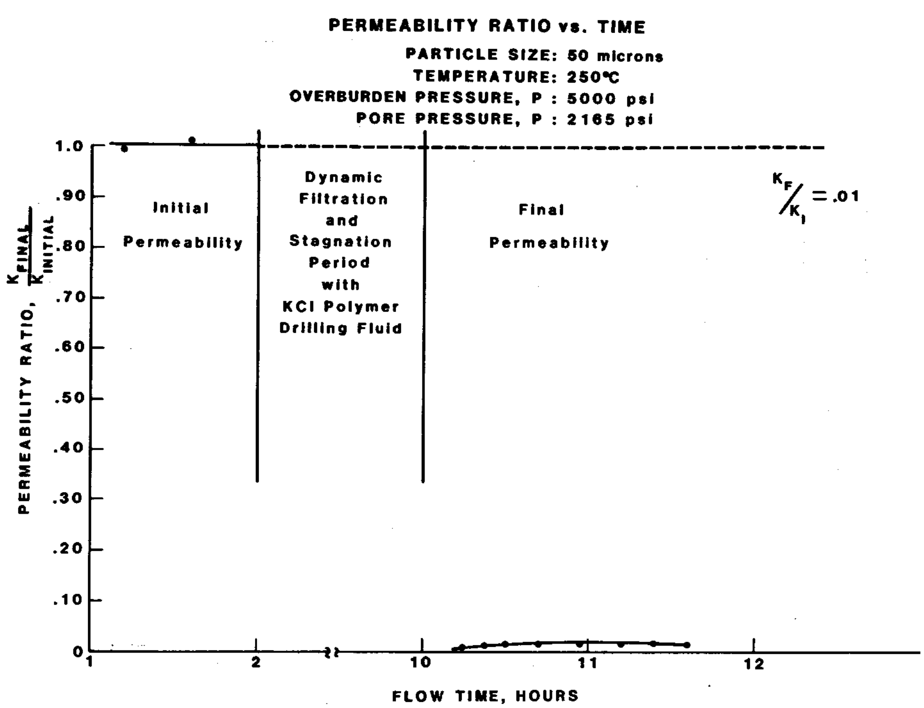


Figure 22. Permeability Recovery at 250°C Using a 50 Micron Sized Particle.

Particle Size Distribution: Four combinations of equal amounts of individual particles were tested at temperature, the combinations were: 5 & 20 microns; 5 & 50 microns; 20 & 50 microns; and 5, 20 & 50 microns. Tests conducted at room temperature found all four combinations yielding good recovered permeability ratios ranging between 0.48 and 0.78. Results from 175°C indicate the 5 & 50 micron combination to be very effective ($K_F/K_I = 0.97$) with the 20 & 50 micron combination also quite good. Tests at the highest temperature - 250°C - found overall performance of the combinations to be poor; the best recovered permeability ratio was only 0.10 produced by the 5, 20 & 50 micron combination. A summary of test results is shown in Table 5. Figures 23 through 34 detail individual recovered permeability at temperatures of 23°C, 175°C and 250°C.

Table 5

Recovered Permeability Ratio vs Particle Size Distribution as a Function of Temperature for a Generic Sandstone

Particle Size	Temperature		
	23°C	175°C	250°C
5 & 20 μ	0.67	0.06	0.08
5 & 50 μ	0.62	0.97	0.04
20 & 50 μ	0.78	0.67	0.02
5, 20 & 50 μ	0.48	0.01	0.10

Temperature Effects: Elevated temperature appears to have the greatest effect on the degree of recovered permeability in these particle tests. All particles and combinations performed poorly at 250°C. This is despite the fact that in tests at lower temperature there were some positive effects in preventing formation damage (as measured by the degree of restored permeability to the sample). The mechanism operating to make the particles less effective at higher temperatures is unidentified at present, but it may be related to the performance of the drilling mud at the elevated temperatures.

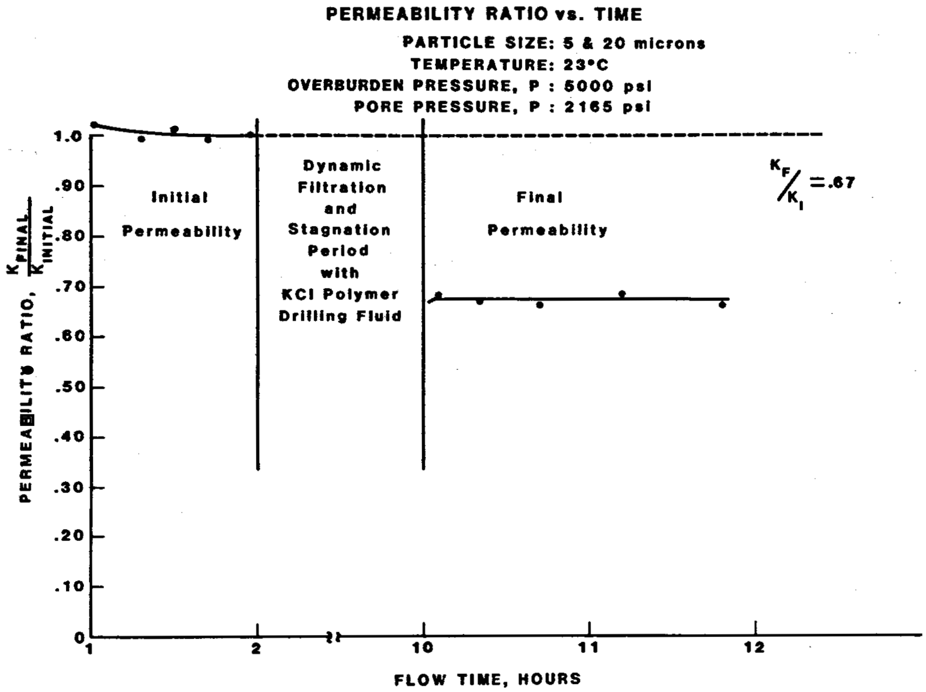


Figure 23. Permeability Recovery at 23°C Using a Combination of 5 and 20 Micron Sized Particles.

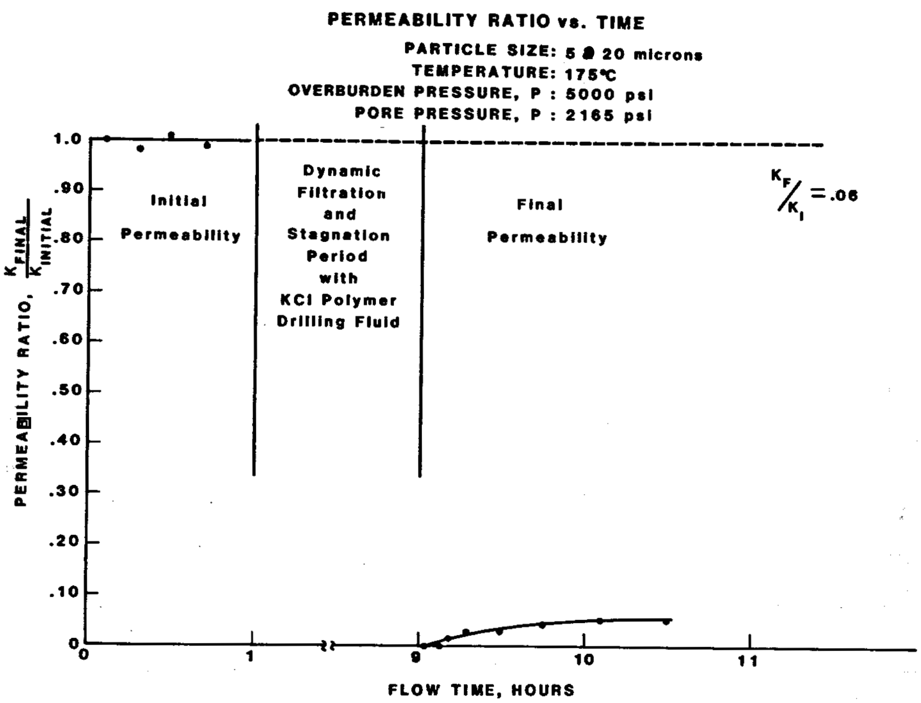


Figure 24. Permeability Recovery at 175°C Using a Combination of 5 and 20 Micron Sized Particles.

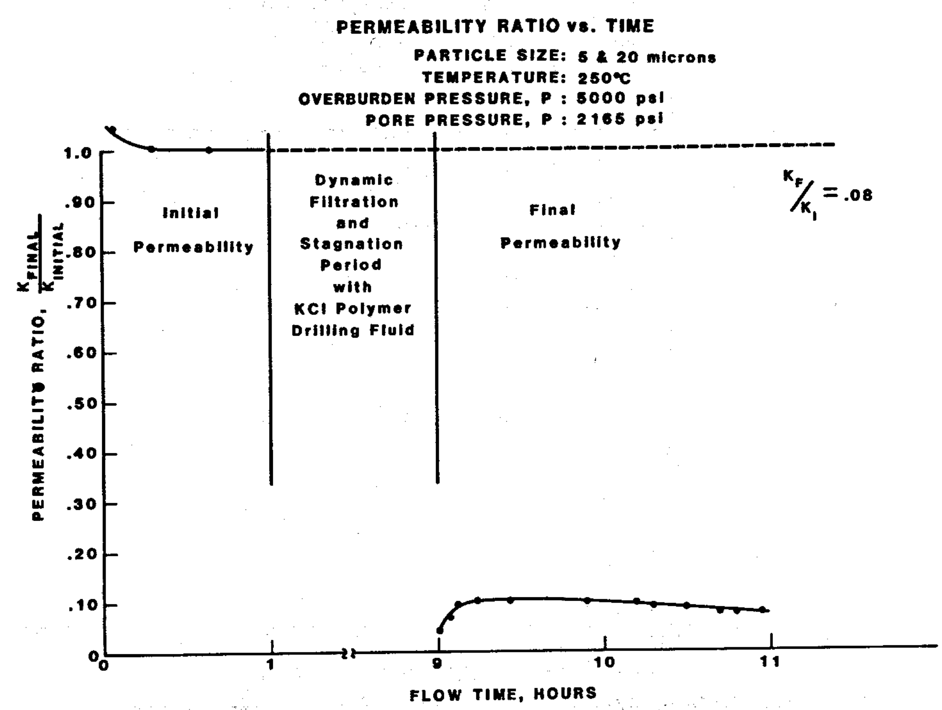


Figure 25. Permeability Recovery at 250°C Using a Combination of 5 and 20 Micron Sized Particles.

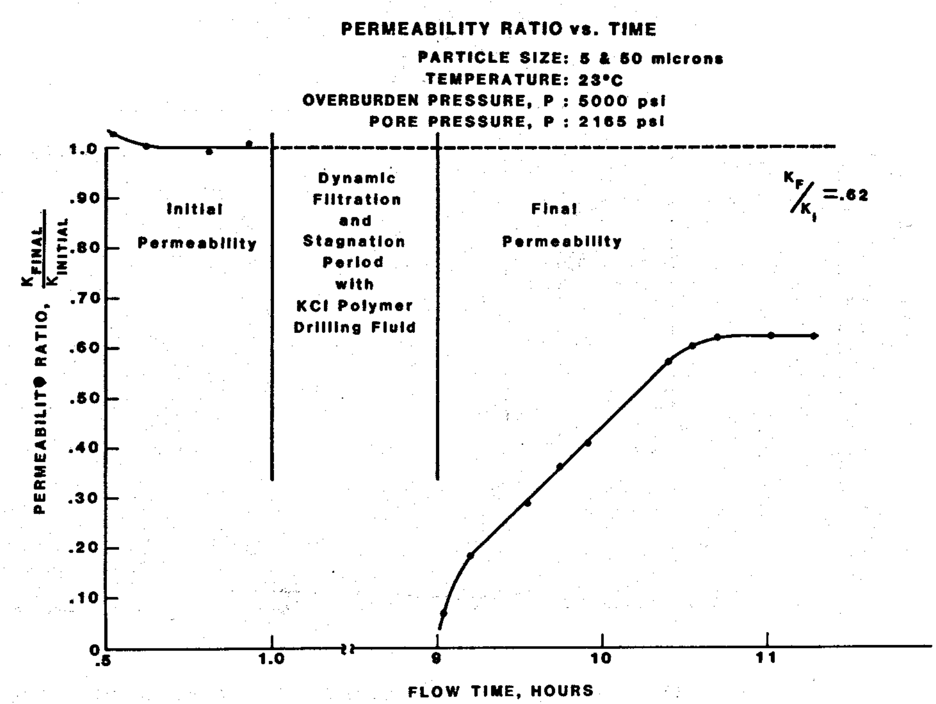


Figure 26. Permeability Recovery at 23°C Using a Combination of 5 and 50 Micron Sized Particles.

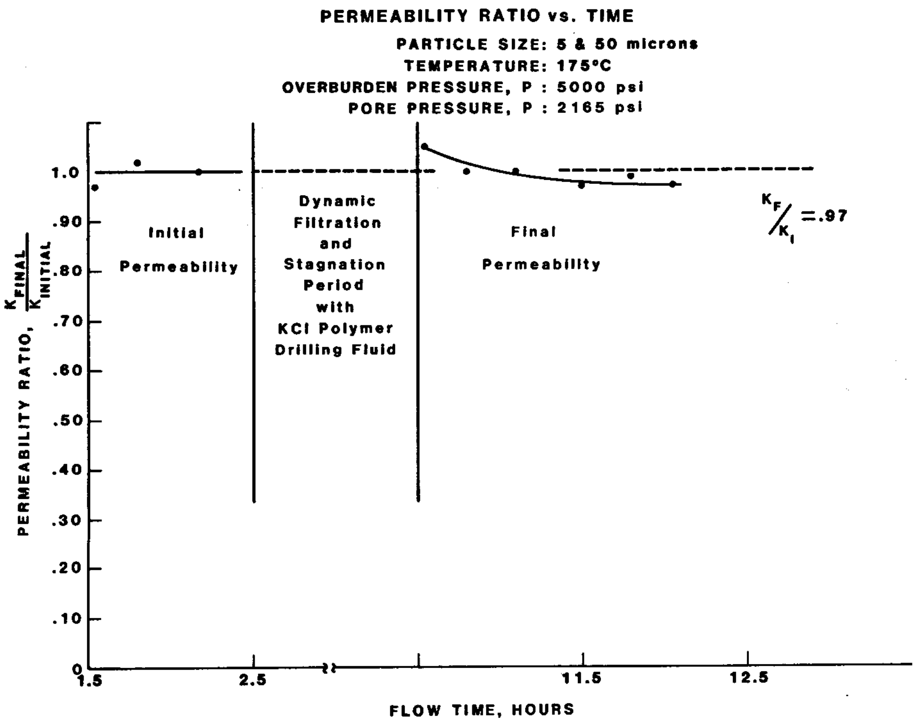


Figure 27. Permeability Recovery at 175°C Using a Combination of 5 and 50 Micron Sized Particles.

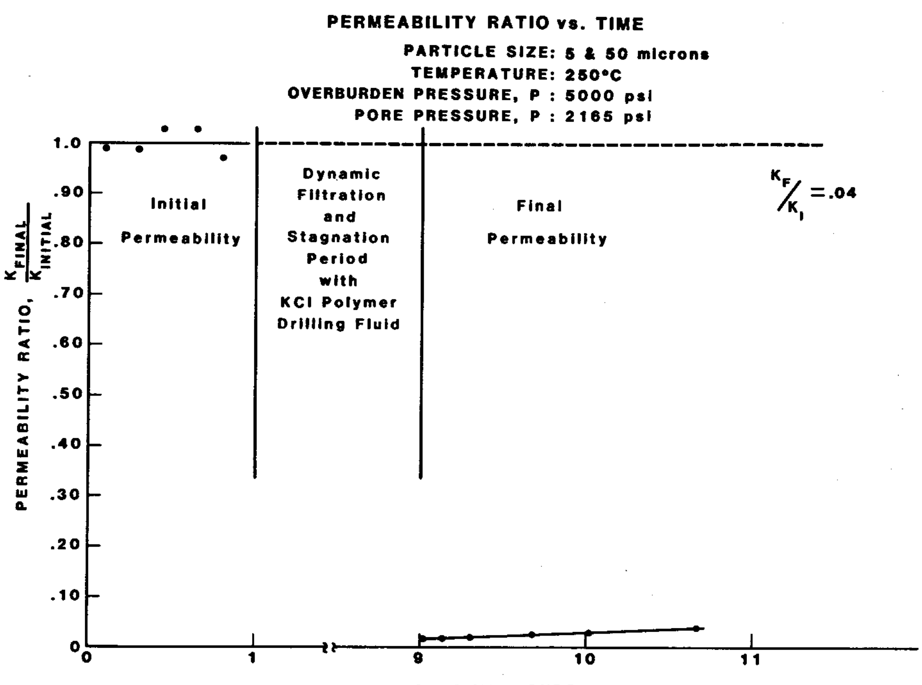


Figure 28. Permeability Recovery at 250°C Using a Combination of 5 and 50 Micron Sized Particles.

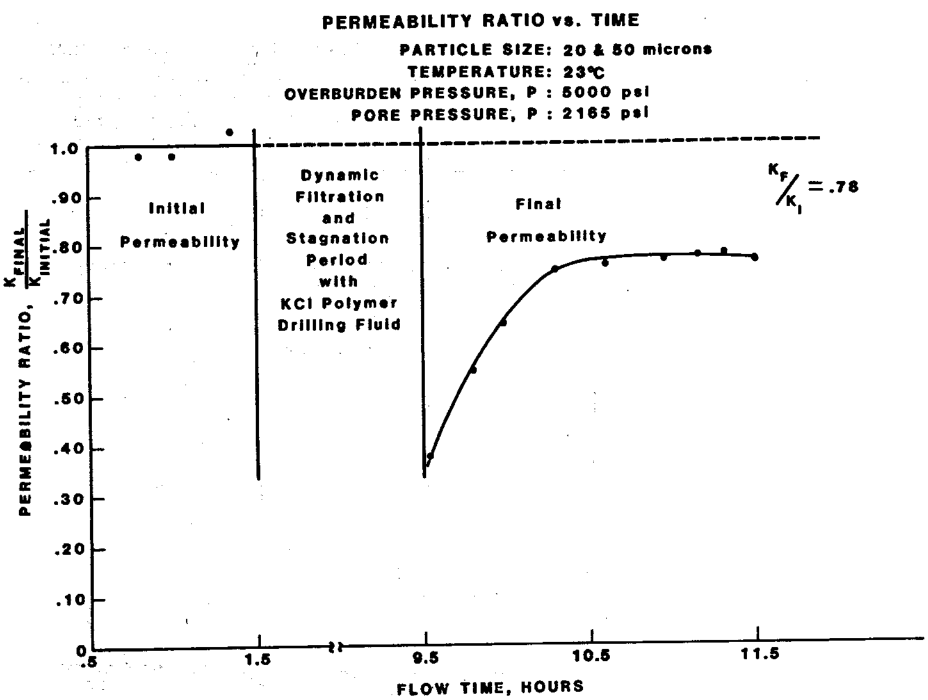


Figure 29. Permeability Recovery at 23°C Using a Combination of 20 and 50 Micron Sized Particles.

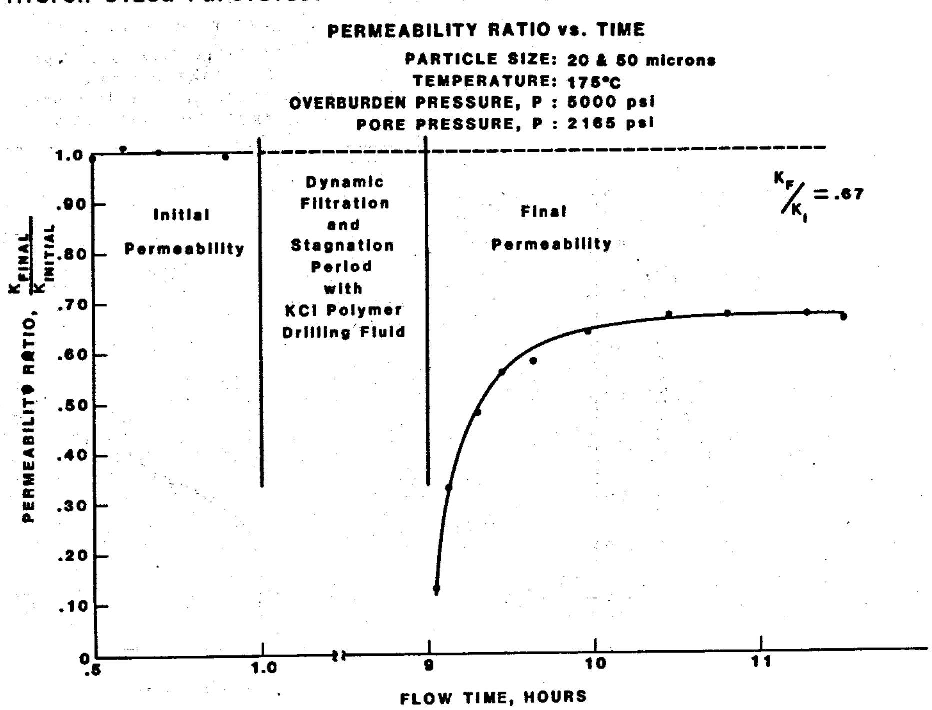


Figure 30. Permeability Recovery at 175°C Using a Combination of 20 and 50 Micron Sized Particles.

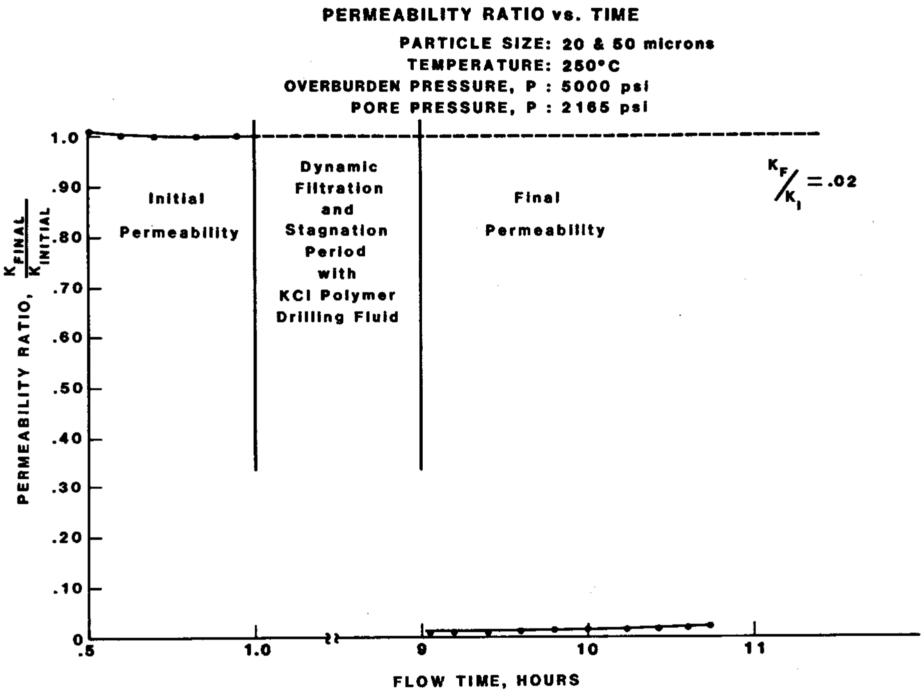


Figure 31. Permeability Recovery at 250°C Using a Combination of 20 and 50 Micron Sized Particles.

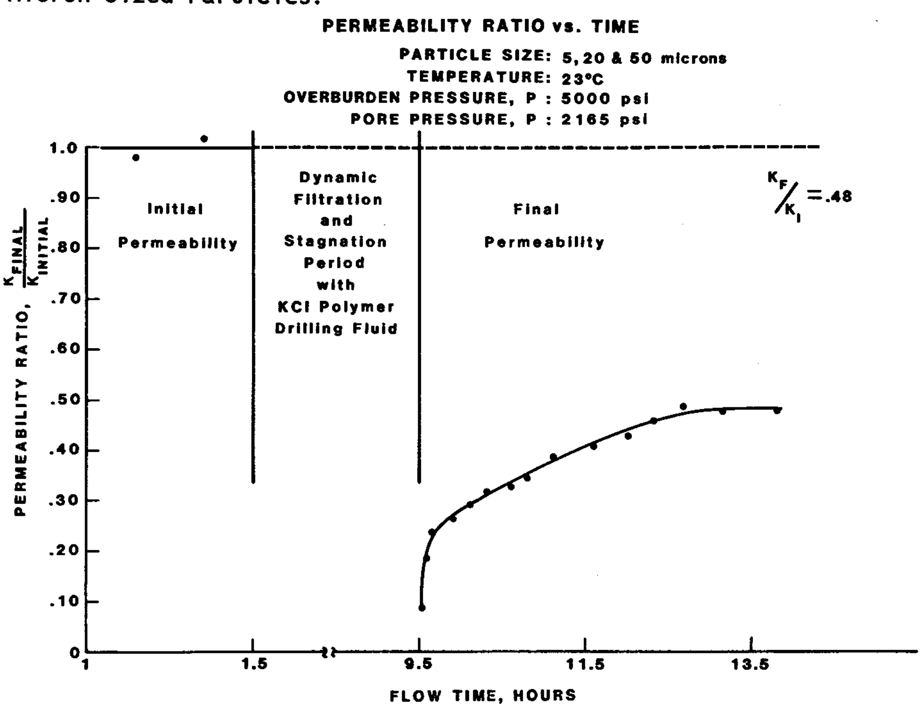


Figure 32. Permeability Recovery at 23°C Using a Combination of 5, 20 and 50 Micron Sized Particles.

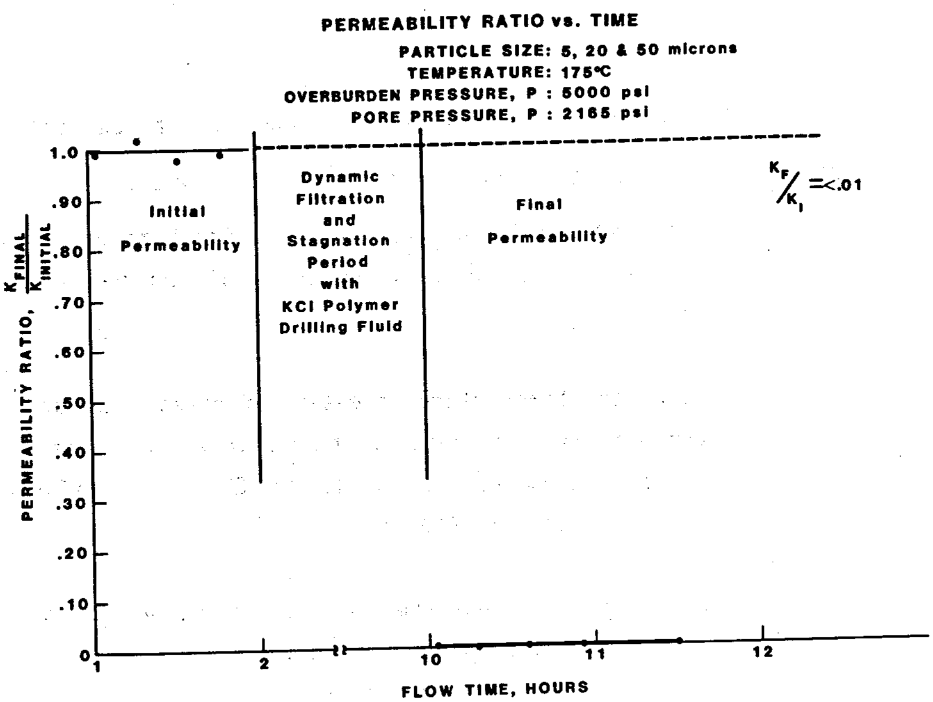


Figure 33. Permeability Recovery at 175°C Using a Combination of 5, 20 and 50 Micron Sized Particles.

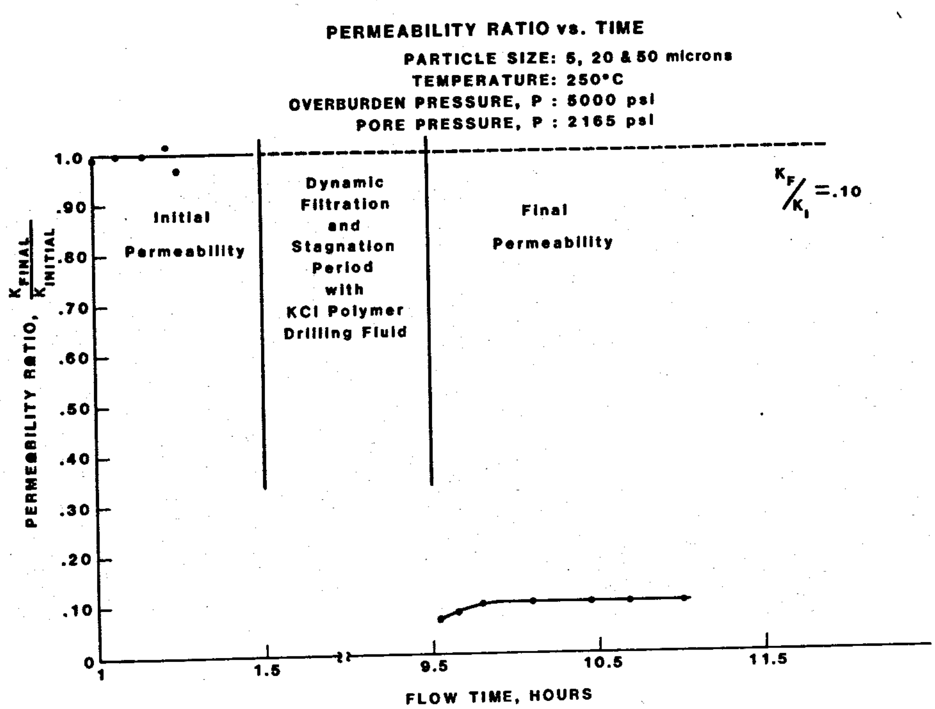


Figure 34. Permeability Recovery at 250°C Using a Combination of 5, 20 and 50 Micron Sized Particles.

Conclusions

The following conclusions can be drawn from the particle size and distribution testing results reported in the previous pages.

1. Recovered matrix permeability was far better when a combination of particle sizes was used in the drilling mud rather than a single size.

2. Increased temperature greatly affected the degree of recovered permeability; at 23°C most particles and combinations had good recovered permeability while at 250°C no particle or combination had satisfactory performance.

3. Correlation between the most effective bridging particle and pore size could not reasonably be established.

FRACTURE SIMULATION

The objective of this phase of the study was to identify and evaluate various core preparation techniques which would be representative of naturally occurring fractures and yet be suitable for laboratory use. It was not the purpose of this project to decide on the definitive fracture model because this task, in itself, would require research well outside the scope of this study. Discussed in the following sections are three techniques to simulate fractures, a description of the capabilities of the test system used to handle the higher flow rates associated with fracture systems, and a technique to measure fracture size.

The method of study decided upon after discussion with personnel involved in geothermal exploration, rock mechanics and the oil and gas industry was to bracket possible successful techniques of fracture simulation by simultaneous development of several different techniques. While considering important fracture parameters, such as rock lithology, aperture, rugosity, tortuosity, asperity heights and flow area, three core samples were prepared which encompassed a wide range of fracture characteristics. Because of the wide diversity of rock lithologies in which geothermal reservoirs are found, the fracture samples were prepared from the two extremes of granite and sandstone. A primary consideration in the development of these fracture samples was the ease by which they could be prepared if needed for testing in large quantities, and the degree of reproducibility each was capable of achieving. The three methods tested were: saw-cutting, sand-blasted saw-cutting, and tensile fracturing.

Most straightforward in ease of preparation and reproducibility was the saw cut sample as shown in Figure 35. Using a diamond saw, the core was cut lengthwise and the fracture faces produced were of consistent texture and quality. This method naturally allowed the easiest duplication of test results under simulated in situ conditions. The saw-cut method has been used in industry and academia. It limits the number of fracture variables and allows easy and direct comparison of test data. The obvious limitations of this technique include the lack of a realistic fracture face texture and tortuosity that is characteristic of fracture flow paths.

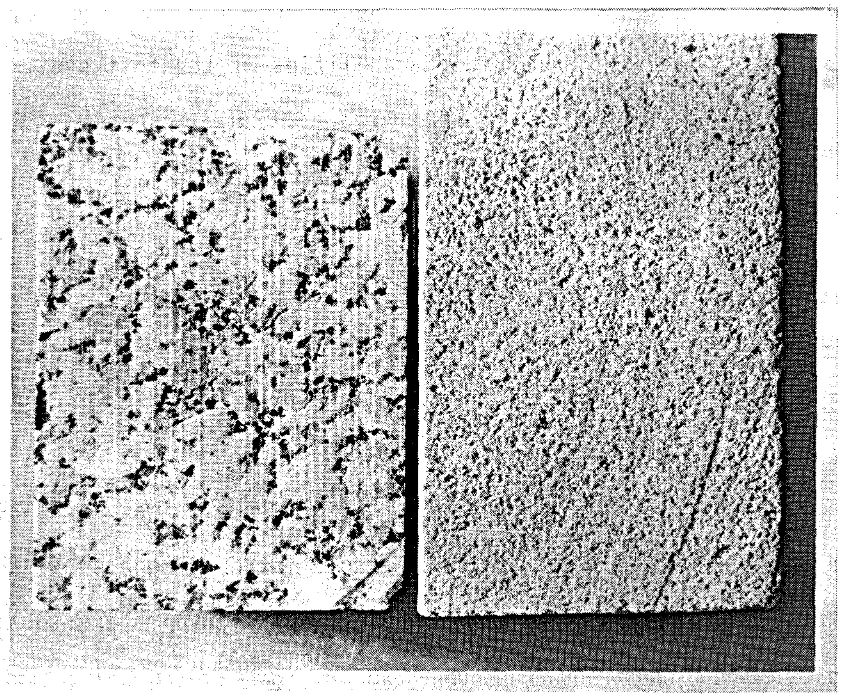


Figure 35. Saw Cut Fracture Simulation.

The second type of fracture simulation consisted of the sand blasting of the two faces of core which had been saw-cut in half, as shown in Figure 36. By using sized beads of 500 microns and 250 microns it was possible to uniformly reproduce a fractured sample containing extensive asperities and good artificially induced rugosity. This method was lithologically dependent in that grain or crystal size determined the degree of texture evident on the

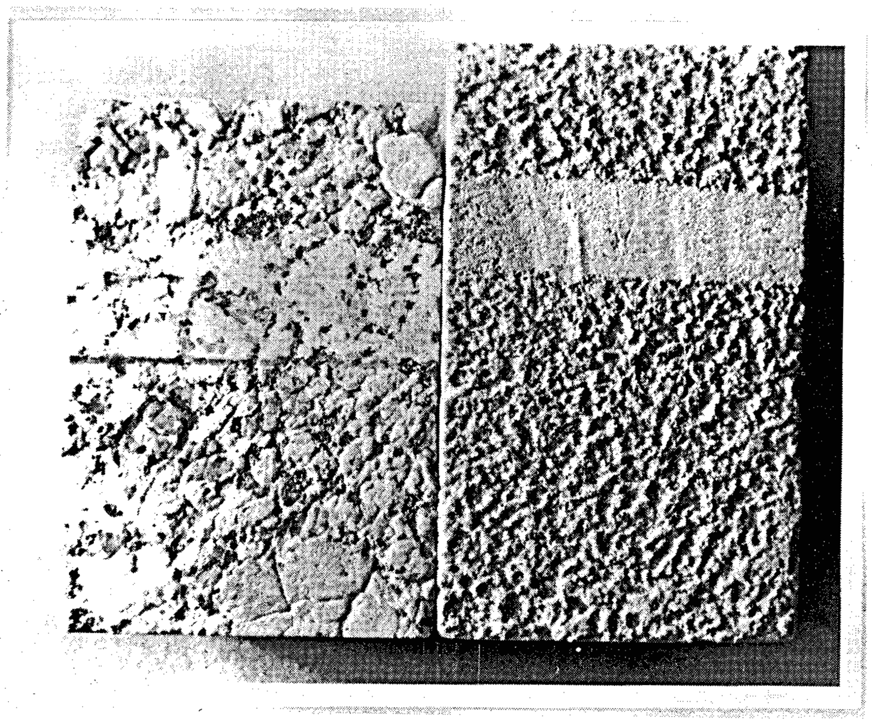


Figure 36. Sand-Blasted Fracture Simulation.

sandstone or granite samples, respectively. Preparation by fine or coarse sand blasting has the advantage of being easily duplicated and also possessing several of the aforementioned fracture characteristics.

Tensile fracturing of a core sample was the third method of fracture simulation in the laboratory. Fractures produced in this manner had overall profiles that resembled naturally occurring fractures as well as good rugosity and asperity properties. Using the Brazil Method to induce the tensile fractures, good reproducibility was achieved on a variety of rock lithologies as shown in Figure 37, but reproducibility was obviously not as consistent as the other techniques. This particular technique required greater care and more time in preparing the fractured sample but probably resulted in a better simulation of a naturally occurring fracture than the two previous methods.

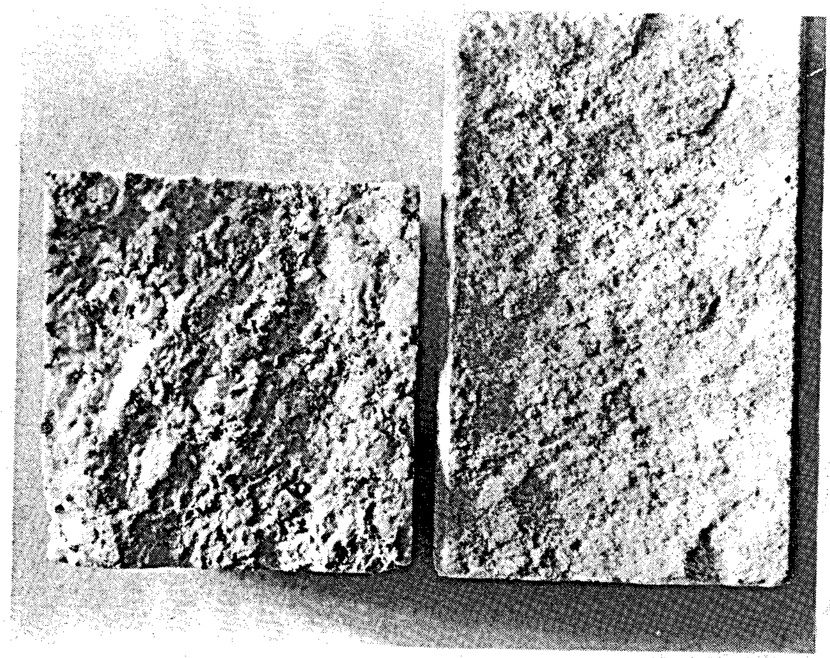


Figure 37. Fracture Simulation Using a Sample with a Tensile Fracture.

Part of the fracture simulation effort called for developing a satisfactory sample jacketing method which could handle simulated geothermal conditions. The tensile fracture sample, because it was the most difficult of the three to successfully jacket, was used to develop a suitable technique. The fractured sample jacketing procedure developed uses 0.005" stainless steel shims placed over the fracture openings to prevent jacket failure along the fracture seams when pressure and temperature reached elevated levels. Following these shims, several layers of shrink-to-fit teflon tubing were placed over the rock/endcap interface and then the entire sample was coated with silicone rubber and additional layers of teflon tubing.

Maximum capabilities of this jacketing technique were determined during debug tests of the fracture flow system. Sample temperature to 500°F (260°C), pore pressure to 5,000 psi and overburden pressure to 10,000 psi were achieved for several hours while hot brine was flowed through the sample. Test duration of forty-eight hours at the pressures above were possible if sample temperature was lowered to 480°F (250°C). Gauging of fracture width during testing was accomplished by using a modified cantilever assembly which was operable to 350°F; further development would be necessary to exceed this temperature.

Simulation of naturally occurring fractures in the laboratory required a determination of the available Terra Tek fluid flow test system's ability to handle the higher flow rates and larger volumes associated with fracture testing. To meet this need, the system was found to require only small modifications in terms of equipment and operating procedures. Analysis indicated that the maximum equivalent matrix permeability the system is capable of measuring at steady-state is in the 400 to 600 millidarcy range. If measurements were for only short durations then the system is capable of a 2 darcy equivalent.

Conclusions

Development efforts have successfully achieved the following:

1) Laboratory simulation of fractures has been achieved under geothermal test conditions using three core preparation techniques. These consist of: saw-cutting, sand-blasting, and tensile fracturing of core samples which are representative of geothermal resources.

2) Design modification needs of the Terra Tek geothermal flow system have been assessed to allow the handling of the higher flow rates and larger volumes associated with fractured systems. Results indicate samples with an equivalent matrix permeability of 400 to 600 millidarcies can be handled at steady-state and for short durations, up to a 2 darcy equivalent can be measured.

3) Measurements of fracture width have been successfully made while testing at simulated geothermal pressures and temperatures up to 350°F. In addition, a suitable jacketing method was developed for fractured samples which allows samples to be tested at temperatures to 500°F.

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APPENDIX

FACILITIES DESCRIPTION

Testing for this program was performed at Terra Tek's geothermal testing facility, Figure A-1. Capabilities of this high pressure-high temperature test facility are summarized:

- Confining pressure to 200 MPa (30,000 psi)
- Temperature to 535°C (1000°F)
- Axial load to 4.5×10^6N (10^6 lbs)
- Sample Size: 5 cm (2") diameter (to 535°C)
10 cm (4") diameter (to 200°C)

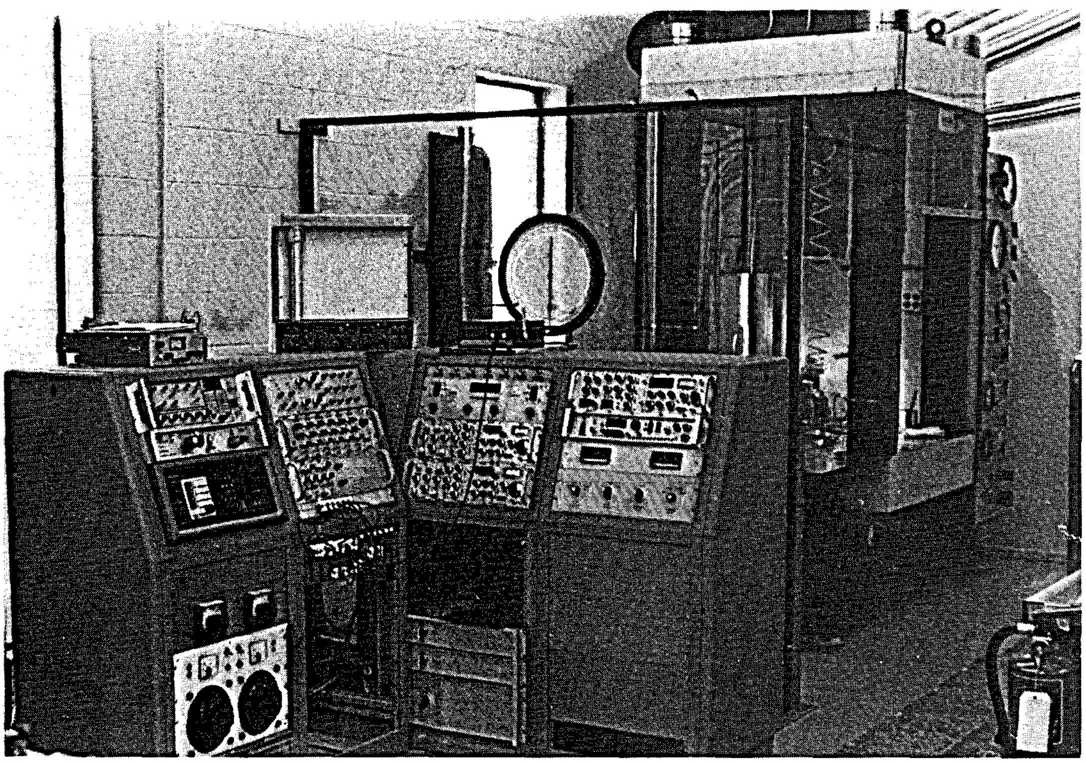

Figure A-1. Geothermal Testing Facility.

While maintaining these previously described environments the following geothermal material properties can be determined:

- Mechanical properties: complete stress-strain response including longitudinal and lateral strains (volume response) and pore fluid pressure.
- Thermal properties: thermal conductivity, thermal diffusivity, thermal expansion coefficient
- Matrix and fracture permeability/conductivity to gases and liquids
- Electrical resistivity
- Ultrasonic velocities

A drilling fluid circulation flow cart was specifically designed and constructed to meet the unique requirements of this testing. Shown interfaced with the geothermal test facility in Figure A-2, this flow cart provides pore pressure, differential pressure and constant monitoring of filtrate and drilling fluid volumes.

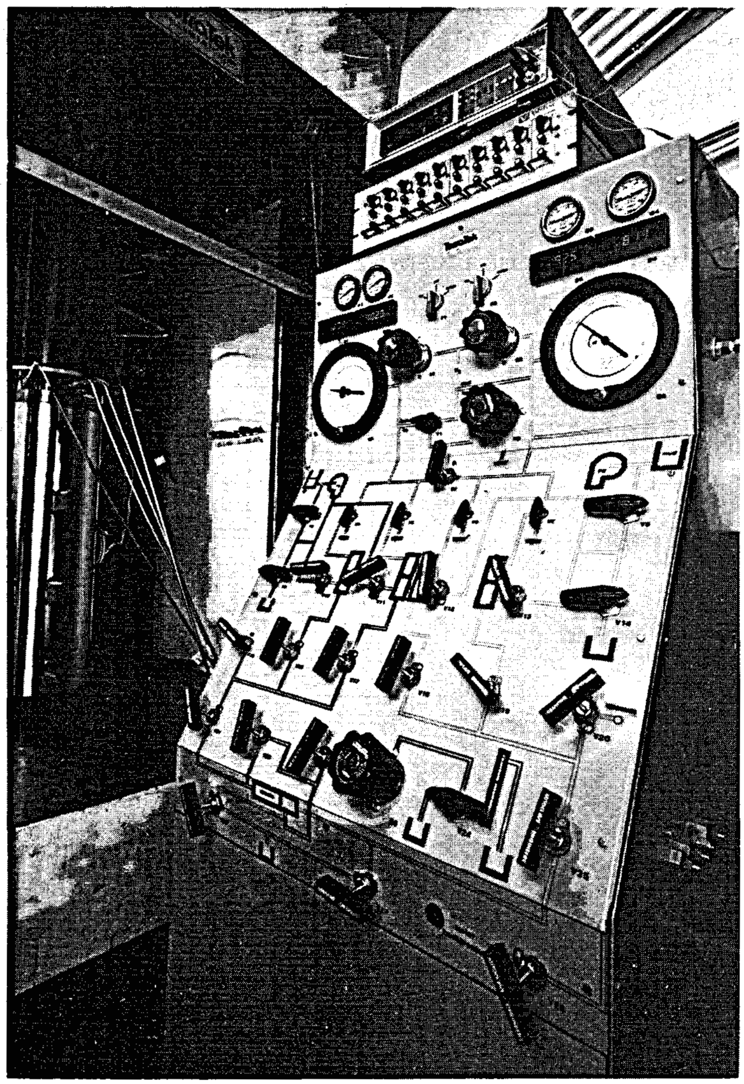

Figure A-2. Photograph of Drilling Fluid Circulation Equipment.

CORE HANDLING PROCEDURES

Proper handling of core specimens during all phases of testing was imperative to the success of the program. The key to achieving this was implementation of a consistent core handling and preparation procedure which all project personnel were familiar with and employed at all times. Discussed here are the general handling and preparation methods used.

<u>Core Storage</u>: Cores used in the Filtrate Chemistry Sensitivity and Long-Term Permeability tests were from the East Mesa KGRA while samples for Particle Size and Distribution testing were a generic sandstone; storage methods differed in these two cases. The test samples from the former have been in storage at Terra Tek since the original coring was completed in 1979. These cores, after being logged in and described at the drilling site, were wrapped in a "saran wrap" plastic material followed by several layers of aluminum foil. The cores were then dipped in beeswax to preserve the as-received moisture content. East Mesa cores used in these particular investigations had never been opened prior to the time they were selected as test samples.

Generic core samples were obtained for a previous test program and the unused material was available for testing of particle size effects. This material was obtained from a large quarried block which had been cored into small samples and was kept in the Terra Tek core shed in field core boxes. No attempt was made to maintain moisture content.

<u>Selection and Coring of Test Samples</u>: Several feet of East Mesa core were examined by binocular microscope. Selection of test samples was based upon maximum homogeneity of lithology from foot to foot. Once completed, a mapping of the available core intervals was done to insure that all samples

used in a particular particle size series or filtrate series were from immediately adjacent areas.

All samples were cored parallel to the bedding planes using a diamond core barrel and air cooling. Using air as a cooling medium required long coring times, however, to properly evaluate formation damage due to filtrate sensitivity the use of any liquid would have resulted in pre-test damage. Once cored, the test samples were wrapped and sealed in beeswax (as previously described) until needed for testing. Total pre-test exposure time to the atmosphere was less than one hour.

Post-Test Handling: Upon completion of testing all samples were de-jacketed and immersed in the pore fluid used in the particular test. Samples remain in marked containers in the Terra Tek core storage cabinet if needed for any post-test analysis.

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