MECHANISMS OF FORMATION DAMAGE IN MATRIX PERMEABILITY GEOTHERMAL WELLS

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ABSTRACT

Matrix permeability geothermal formations are subject to damage during well drilling and completion. Near well bore permeability impairment that may occur as a result of particulate invasion, and chemical interaction between formation clays, drilling mud filtrates and formation brines is investigated.

Testing of various filtration chemistries on the permeability of East Mesa sandstone indicates that permeability is significantly impaired by the flow of low salinity formation brines. This damage is attributed to cation exchange and removal processes which alter the stability of clay structures. Fluid shearing dislodges particles, which clog pore throats, irreversibly reducing permeability.

The test program investigating the effects of mud-transported particles on geothermal formations is still in progress. The rationale, apparatus and test procedures are described. Final results of this testing will be presented at the conference.

INTRODUCTION

"Formation damage" is a term used throughout the industry to describe negative interaction between the drilling operation and producing formation resulting in an impaired near well bore permeability. Coincident with this permeability impairment is a reduction in production. In a geothermal well where economic viability is predicated upon the production of prodigious amounts of heated water and/or steam, formation damage must be understood, controlled and minimized.

The use of air as a drilling fluid is clearly a desirable alternative to minimize formation damage, but is not practicable in all circumstances. Whenever drilling muds are introduced into the borehole in an "over balanced" pressure situation, mud invasion and formation damage occur.[1] Hydrothermal wells are particularly sensitive to this invasion because of the long completion zones, complex chemistries and high temperatures. Solids plugging, precipitates, matrix/filtrate interaction, or any combination can result in serious near well bore permeability impairment.

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 made successful transitions to geothermal applications (e.g., perforation, acidization). The program described in this paper addresses the problem of formation damage from the perspective of geothermal fluid production. For this discussion the mechanisms of formation damage are divided into two major categories: filtrate induced damage and particulate induced damage. Testing to date has focused upon matrix permeability dominated reservoirs such as East Mesa, but future program plans have been formulated to address the interaction of drilling fluids with producing fractures. Additionally, field experiences have suggested that operational procedures (e.g. rate of backflow, surging upon re-entry, etc.) can impact the magnitude of permeability impairment, but these effects are beyond the scope of this discussion.

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FACILITIES DESCRIPTION

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

- Confining pressure to 200 MPa (30,000 psi)
- Temperature to 420°C (800°F)
- Axial load to 4.5 x 10^6N (10^6 lbs)

Sample size: 5 cm (2") diameter (to 420°C)
10 cm (4") diameter (to 150°C)

With this facility, overburden stress, pore fluid pressure, temperature, and pore fluid chemistry can be controlled to simulate the in-situ state of the reservoir. A flow system, Figure 2, interfaces with the test machine and provides the means to circulate permeating brines and drilling fluids. Test parameters such as fluid volume, differential pressure, temperature, etc. are continually monitored by digital computer, providing real time data acquisition and reduction. The system is designed to accommodate extended duration testing during which a single test may continue for weeks.

FILTRATE INDUCED DAMAGE

Background

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. A number of factors can influence this interaction and are discussed in the following sections.

Salinity Contrast: The 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" exists that disturbs the clay equilibrium and is potentially detrimental to the productivity of the well. Ionic exchange between the filtrate and the clay minerals can result in clay hydration accompanied with 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[5] have demonstrated that clay dispersion and permeability impairment will occur even when only small percentages of clay are present within the pore space.

It has been demonstrated by Jones[3] that an invading filtrate, 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.

Exposure Rate: Research has shown that permeability blockage due to clay sensitivity is also dependent upon the rate at which pore fluid is replaced by invading filtrate.[3] Rapid exposure to filtrate results in more permeability reduction than slow exposure. Past work is limited to room temperature; high temperature response is not known. The ability to reverse these blockage effects is similarly not known.

pH Effects: Formation clay detachment and dispersion is affected by the pH of the invading filtrate. Recent work[4] using scanning electron microscope (SEM) techniques has demonstrated this effect on clay particle disturbances in sandstones. Clay mobility within the pore space was shown to increase with increasing invading fluid pH. The in-situ pH of many geothermal fluids ranges from 3.0-5.0 due to the high temperatures and after production may have a pH of 10.0-11.0.

Precipitation Reaction: Geothermal formation fluids contain particular anions and cations which, when placed in contact with ionic constituents in the filtrate, will form insoluble precipitates. For example, some formation fluids in the Imperial Valley contain free barium. Sulfates in the drilling fluid makeup water or chemical additives result in an insoluble precipitate, barium sulfate, being formed.[6]

Additives: An additional problem encountered in geothermal mud systems is mud properties degradation at formation temperatures. This necessitates considerable mud maintenance effort and the addition of polymers, thinners and corrosion inhibitors to maintain the desired rheological properties. Interactions of these chemicals with the formation clays and formation fluids at the elevated temperatures can contribute to the overall permeability reduction.

A laboratory test program was designed and performed to examine "salinity contrast" effects in core obtained from East Mesa, KGRA.

Experimental Program

An experimental program was designed to investigate permeability alterations due to salinity contrast exposure as a function of filtrate chemistry and temperature in an East Mesa sandstone. All permeability measurements were made at simulated conditions of temperature, overburden pressure and pore fluid pressure. Initial permeability measurements were made with a synthetic pore fluid formulated on the basis of water chemistry analysis performed by the well site operator. Shown in Table 1 is the chemical analysis of East Mesa brine. Test samples were then exposed to a filtrate solution specifically formulated with an ion chemistry reactive with the formation. Exposure conditions were designed to model the conditions existing during drilling and completion. Permeability after exposure to this filtrate was also determined under in-situ conditions and compared to the initial permeability measurement to determine the extent of damage due after exposure.

Samples were exposed to the following constant simulated in-situ conditions:

Overburden Pressure: 34.5 MPa (5000 psi)
Pore Fluid Pressure: 14.9 MPa (2165 psi)

Four different filtrate brine solutions 3% KCl, 3% $CaCl_2$, 3% NaCl, and deionized water were tested at temperatures which ranged from 23° to 250°C (reservoir temperature ≅150°C) to determine if there was a temperature dependence. The significance of pH, precipitation reactions, and mud additives is not presently addressed, but will be evaluated in future work.

Material Description: The sandstone core samples used in this testing are from the 5500 foot zone of Republic Geothermal Well 78-30RD, located in the East Mesa KGRA, Imperial Valley, California (Figure 3). 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. Analyses 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.[7]

Initial permeabilities in the 5500 foot section of between .05 md to 20 md have been measured with porosities ranging from 14 to 25%. This section is 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 higher mixed layer clay percentage. A mineralogical and physical properties analysis based on counting 400 points in each thin section is contained in Table 2.

Results

Figures 4 and 5 demonstrate the permeability response of exposure to filtrate solutions of calcium chloride and sodium chloride, and are similar to tests at other temperatures and with other filtrate solutions (potassium chloride and deionized water). The most significant common feature of the 16 tests in this series is the substantial decrease in permeability during the initial flow of synthetic East Mesa brine. Permeability decreases of 50 to 80 percent were experienced during the East Mesa brine sections of each test.

Sensitivity to low salinity (2000 ppm) brines was not originally envisioned in this formation, since it contained very small amounts of swelling montmorillonite clays. It was suspected that a system induced error was responsible for the decrease in permeability. To find the source of any such error extensive checks of the entire flow system were made. Filtering systems were examined for possible artificially induced particles; operating procedures were carefully scrutinized. But further permeability tests of this material on other systems, and tests of this systems' ability to confirm permeability measurements made elsewhere, eliminated suspicions of systematic error.

To test the other possible explanation for permeability impairment (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 6). Note that the introduction of the simulated pore fluid resulted in a severe impairment over the course of 10 hours before stabilizing at a value 70 percent below the stable KCl permeability. The reduction in permeability in this test could be attributable strictly to "salinity contrast", which is flow of low salinity fluid following a fluid of higher salinity. (This effect has been documented by Gray and Rex (1966) and by Jones (1964).) But this phenomenon does not explain the permeability decrease during tests only using East Mesa brine. The response to East Mesa Brine was shown in further tests to be a particle damage effect, as demonstrated by the partial restoration of permeability following periods of reverse flow.

It is suspected that the damage mechanism is alteration of the clay structure by ionic exchange or depletion. The clay structure, once altered, is very fragile and is easily damaged by the shear forces of fluid flow. Gray and Rex[5] 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 mix layer clays also exhibited mobility. (Note the presence of illites and chlorites in the analysis of East Mesa Sandstone in Table 2.)

Additional evidence of clay ion substitution is shown in Figure 7. Effluent samples taken during a long-term permeability test with East Mesa brine show that substantial quantities of potassium are being removed during early portions of the test. It is possible that some sodium-potassium exchange is taking place (as observed by Reed (1976)[8]) 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. Figure 7 also shows evidence of carbonate extraction coincident with decrease in permeability. This phenomenon was also observed by Reed (1976)[8] who concluded that removal of the carbonate cementing would free particles to migrate. It is probable that this mechanism contributes interstitial fines which act with clay particles to clog pore throats.

Conclusions

Pore fluid effects in 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 brine of approximately 2000 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 contributing to pore throat blockage.

4. Once the formation matrix has been damaged by exposure to a low salinity brine, subsequent treatments with high salinity filtrates produce little or no effect upon 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.

PARTICLE INDUCED DAMAGE

Background

Particle Size: During the internal filter cake generation, 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. Filtrates, 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.

Particle Shape: Because the bridging phenomenon is not well understood, it is difficult to speculate upon the relative effects of particle shape. Natural particles, having undergone numerous shearing and grinding operations, are generally very ragged and sharp. When bridging occurs, particles are wedged and forced into pore throats by the differential pressure. It is conceivable that spherical or oblate bridging materials of similar size might bridge as well but not wedge or be entrapped. When backflow occurs, these particles will "unlock" and clear the throat obstruction.

A series of laboratory tests is underway to further define these influences.

Material

The sandstone being tested is very fine to fine grained and fairly well sorted with rounded to subangular grains of quartz cemented with calcite. This core meets the criteria for selection which required a "clean" homogenous, well-sorted sandstone with 15% to 25% porosity and trace quantities of expandable clays.

Experimental Procedure

Work in progress at Terra Tek is investigating the role of particle size, shape and concentrations in geothermal formation damage. Particles of aluminum oxide suspended in drilling mud are brought in contact with rock samples at simulated in-situ geothermal conditions of temperature and pressure. Some previous work has used calcium carbonate particles,[9] but aluminum oxide was chosen due to availability of uniform, durable, chemically inert, high-purity particles in the sizes of interest. Since the average pore size of the sandstone is approximately 20 microns, tests in progress employ 5, 20, and 50 micron particles, both in single size and multiple size range tests. (Each size stated is the mean of a normal distribution.) The test matrix is shown in Table 3. The aluminum oxide particles are generally blocky-cubic, and the quantities present attempt to simulate drilling conditions. Future tests could vary the shapes and concentrations of particles.

Test Configuration

A simplified flow schematic of the test system is shown in Figure 8. The test sample is located immediately above a stainless steel cavity designated as the "mud chamber". This chamber and the lower face of the test sample create an interface simulating the wellbore annulus and the formation. Contents of this chamber can be dynamically agitated by a motor driven stirrer.

The test sample is jacketed using layers of heat shrink teflon tube and silicone rubber (RTV). This prevents flow along the sides and isolates the internal pore fluid from the confining fluid.

The sample is placed within the pressure vessel as shown in Figure 9. Heating to test temperature is accomplished by an internal heater with ceramic shrouds to control heat loss. The sample is fully instrumented to provide relevant temperature data. Flow lines are attached to the sample and are interfaced with the "mud circulation cart". Within this flow cart are the pore fluid accumulators which are used to generate pore pressure. Piston displacement within these accumulators is monitored electronically to within 0.1 percent providing a continuous record of fluid movement within the system. Pressure is generated by using a high pressure nitrogen system designed to provide stable long-term pressures.

Initial Permeability

Following the application of confining pressure and pore pressure, the sample temperature is increased at a rate of approximately 0.5°C/min. to the desired test temperature. The system is allowed to stabilize for a period of approximately 1-2 hours. Brine flow is then initiated across the sample in the direction of backflow (top of sample to "mud chamber") by a constant pressure technique. Gas pressure, held constant by precision regulators and large reservoirs within the flow cart, is used to drive the upstream accumulator at a slightly higher pressure (.07 MPa) than the downstream accumulator, creating a pressure differential through the sample. Control methods for the downstream accumulator are similar. Volume change recorded against a time base is used to determine the flow rate through the sample. Flow is allowed to continue for a minimum of two hours or until steady-state flow is achieved. Permeability is 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 is equalized through the sample and the pore fluid occupying the "mud chamber" is slowly displaced by the particle-laden drilling fluid. Several "chamber volumes" of drilling fluid are flowed through the "mud chamber" to ensure that all pore fluid has been displaced.

A pressure differential is then established across the test sample with the drilling fluid pressurized approximately 1.4 MPa (200 psi) above the pore fluid pressure which is maintained at 14.9 MPa (2165 psi). This pressure differential and flow is opposite in direction to the permeability measurement and simulates the loss of drilling fluid from the wellbore annulus to the formation when a hydrostatic overbalance conditions exists. To simulate downhole circulation and to prevent particle settling, the drilling fluid is dynamically agitated by a motor driven stirrer located in the "mud chamber". Drilling fluid is slowly exchanged through the chamber during this "dynamic" period, allowing generation of a dynamically stable equilibrium filter cake. This dynamic filtration is continued until "steady-state" filtrate loss through the sample is experienced. The duration of this filtration varies depending on the permeability of the rock, the test temperature and the drilling fluid being used, but in general lasts about two hours. At this point the dynamic agitation and drilling fluid circulation cease, but the differential pressure is maintained. This stagnation or static filtration phase lasts approximately six hours. The confining pressure, pore fluid pressure and temperature are kept stabilized at specified levels. Rate of filtrate flow is monitored and recorded for the duration of static filtration.

Final Permeability

Stagnation or static filtration is terminated by equalizing the pore pressures on both ends of the test sample. Drilling fluid is then displaced from the "mud chamber" by pore fluid. No attempt is made to remove the filter cake formed upon the face of the sample either by mechanical or chemical means. Backflow is then initiated in the opposite direction of mud penetration in the same manner that the original permeability was conducted. Flow is maintained for approximately two hours, during which time the pressure differential across the sample is maintained at a constant .07 MPa (10 psi). Flow data recorded during this period is used to calculate the final permeability which is compared to the virgin value.

Results

The testing program is still in progress. Results of the testing to date indicate that bridging is occurring (as evidenced by a gradual restoration of backflow permeability after formation damage), but the limited number of tests performed to date is not sufficient to yield exact relationships between pore size and bridging particle size necessary to prevent severe damage. Final results of this testing will be presented at the conference.

SUMMARY

Formation damage occurs as a result of a complex interaction of the drilling fluid (chemical, filtrate and particulate) with the reservoir fluid and formation. A basic understanding of these interactions and their magnitude is prerequisite to quantifying the extent of damage occurring during drilling and completion operations and to the development of methods to minimize the severity of production impairment. Previous work in this area has been conducted from the perspective of oil/gas production and has led to the development of solutions somewhat unique to that industry, e.g. oil based drilling fluids, etc. Solutions and procedures compatible with high temperature formations, complex chemistries and large water production volumes are required to eliminate or minimize this inhibition to geothermal development.

Permeability impairment due to the chemical interaction of drilling fluid with the producing formation is a phenomena uniquely associated with a matrix permeability reservoir. Because of the dependence of this interaction upon interstitial clay content, the response of the formation will be site specific. Test results on the East Mesa sandstone indicate an alteration of interstitial clay by contact with a low salinity brine and subsequent migration of fines resulting in significant pore throat blockage. The results of this testing indicate permeability can be severely and irreversibly impaired by this mechanism. The material from this zone contained only small amounts of clay materials. Further, it was hypothesized that whatever interstitial clay was present would be low in sensitivity because of having been hydrothermally altered. Clearly this is not the case. Because of the site specific nature of this response, it is not possible to extrapolate this behavior even to other zones within the same well. It does, however, clearly identify a major mechanism of formation damage in geothermal wells. Additional studies will be required to address the influence of pH variation, exposure rate, additives and precipitation reaction.

Particle induced damage has been demonstrated to be a major mechanism of formation damage in oil/gas applications, and it is most probable that it will play as important a role in geothermal formation damage. The initial efforts of the particle damage experimentation described in this paper are directed toward matrix permeability material (generic). Particular emphasis is being given to the size relationships among the bridging particles and to the drilling fluid transporting the particles. The drilling fluid holding the particulate within the pore space is a key element to the reversibility of the process. Testing is currently underway and the results will be presented at the conference.

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Table 1: East Mesa Brine Analysis

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

Table 2: East Mesa Minerological & Physical Properties

Sample Depth	QUAR	PLAG	ALKA	MICA	ILLI	IMIX	CHLO	CALC	MEAN GRAIN SIZE (mm)	MEASURED POROSITY (Vol 5%)
5505	63.4	6.0	11.5	-	5.4	4.9	4.4	4.3	.12	15
5506	75.8	5.4	10.4	-	-	-	2.7	5.8	.09	14
5515	76.9	8.8	10.7	-	-	-	1.2	3.5	.20	17
5522	70.2	8.2	12.4	-	3.7	-	3.0	2.5	.13	18
5528	75.5	5.9	9.2	-	3.8	-	3.1	2.6	.13	23
5531	71.0	8.1	8.6	-	4.0	-	5.5	2.7	.15	20
5560	60.4	7.8	15.3	-	5.8	7.1	2.1	1.5	.09	--

Table 3: Particle Damage Test Program

Test Temperature (^oC)	Particle Size (microns)						
23	5	20	50	5 & 20	5 & 50	20 & 50	5 & 20 & 50
175	5	20	50	5 & 20	5 & 50	20 & 50	5 & 20 & 50
275	5	20	50	5 & 20	5 & 50	20 & 50	5 & 20 & 50

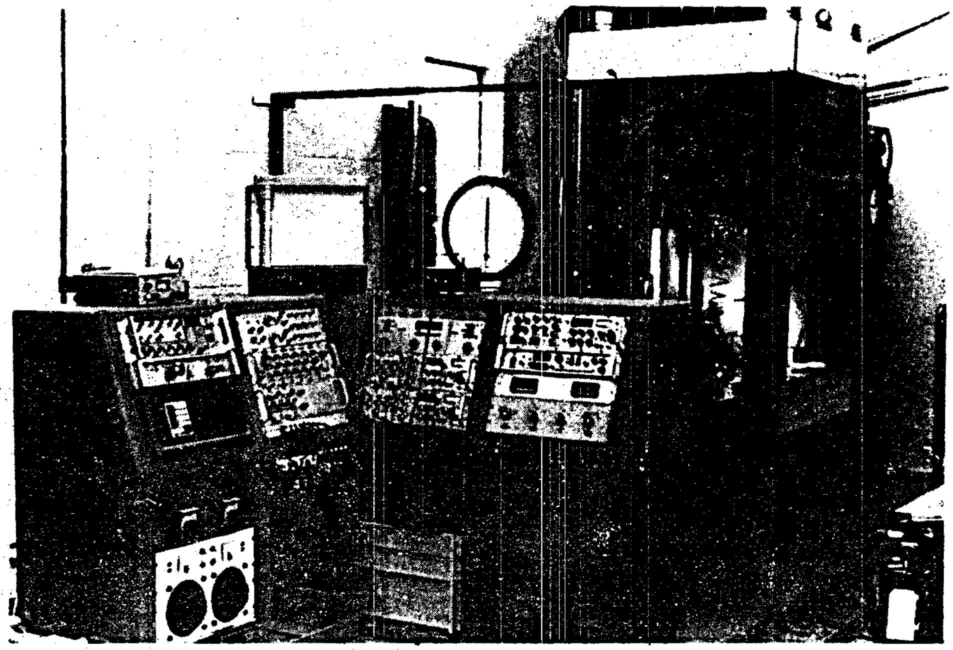

Figure 1: Terra Tek Geothermal Test Facility

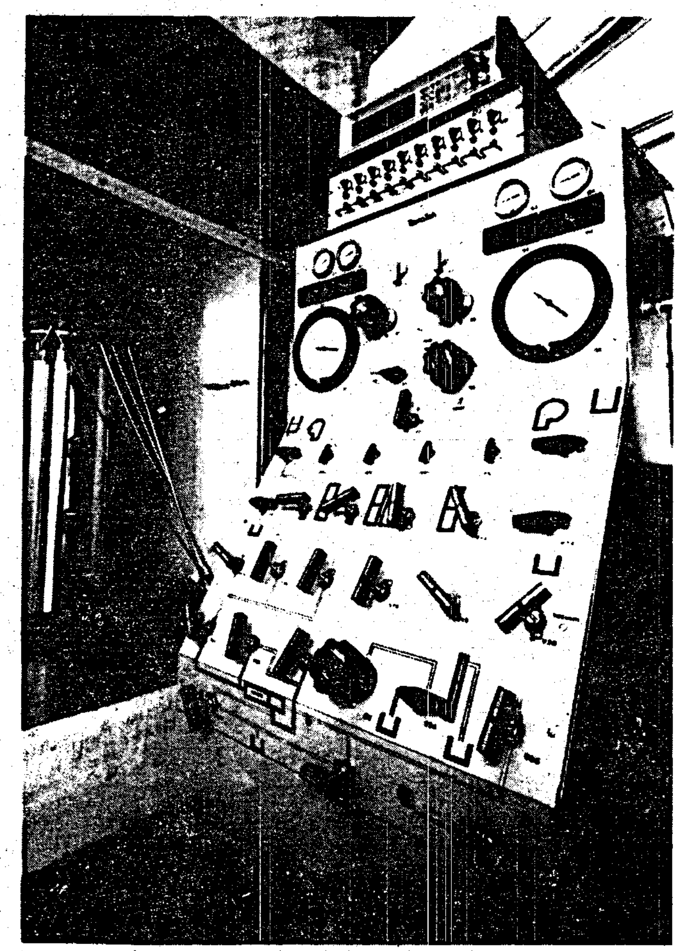

Figure 2.: Permeability Fluid Flow System

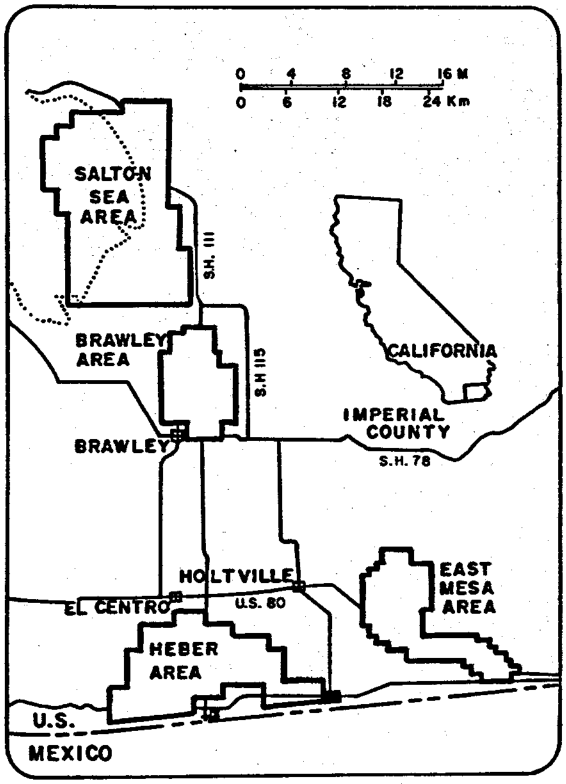

Figure 3. KGRA of Imperial Valley, California.

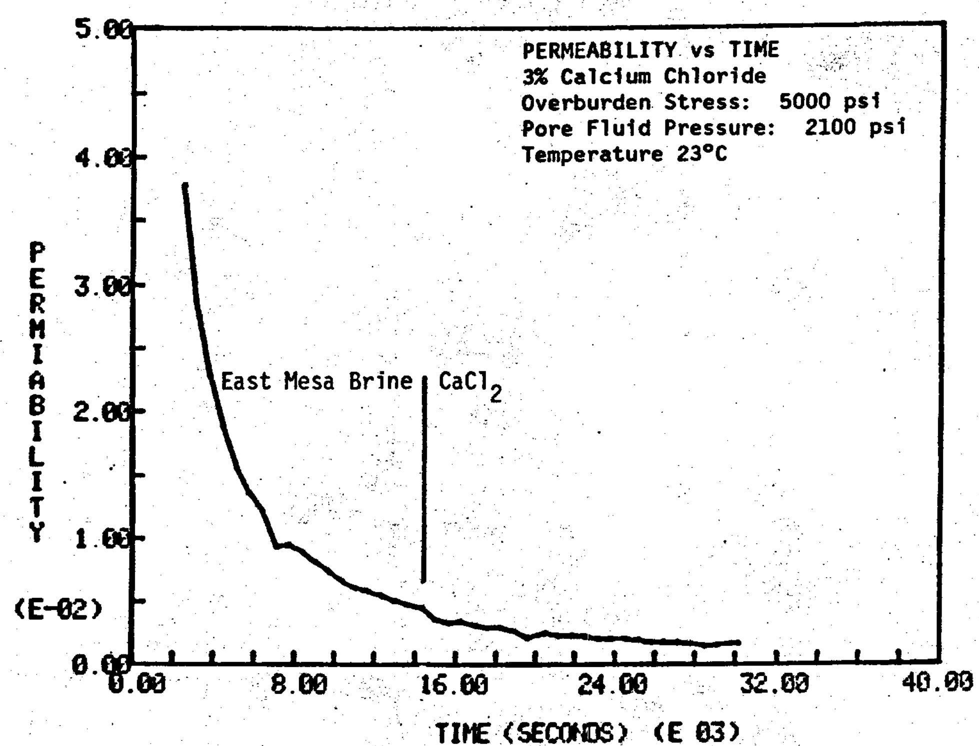

Figure 4: Permeability vs. Time
Low to High Salinity Contrast ($CaCl_2$)

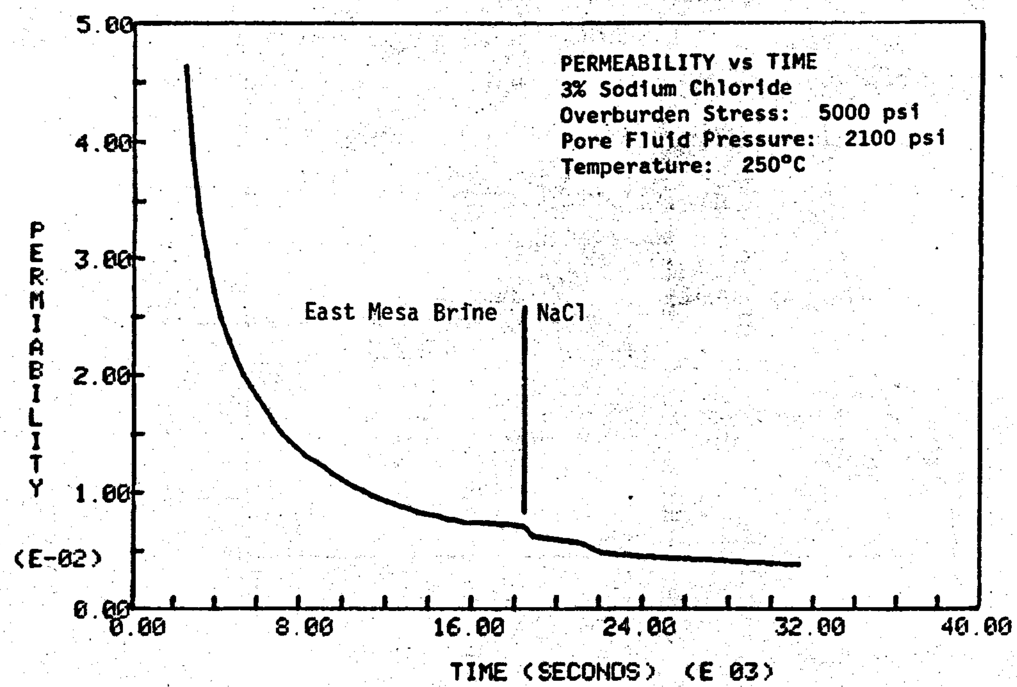

Figure 5: Permeability vs. Time
Low to High Salinity Contrast (NaCl)

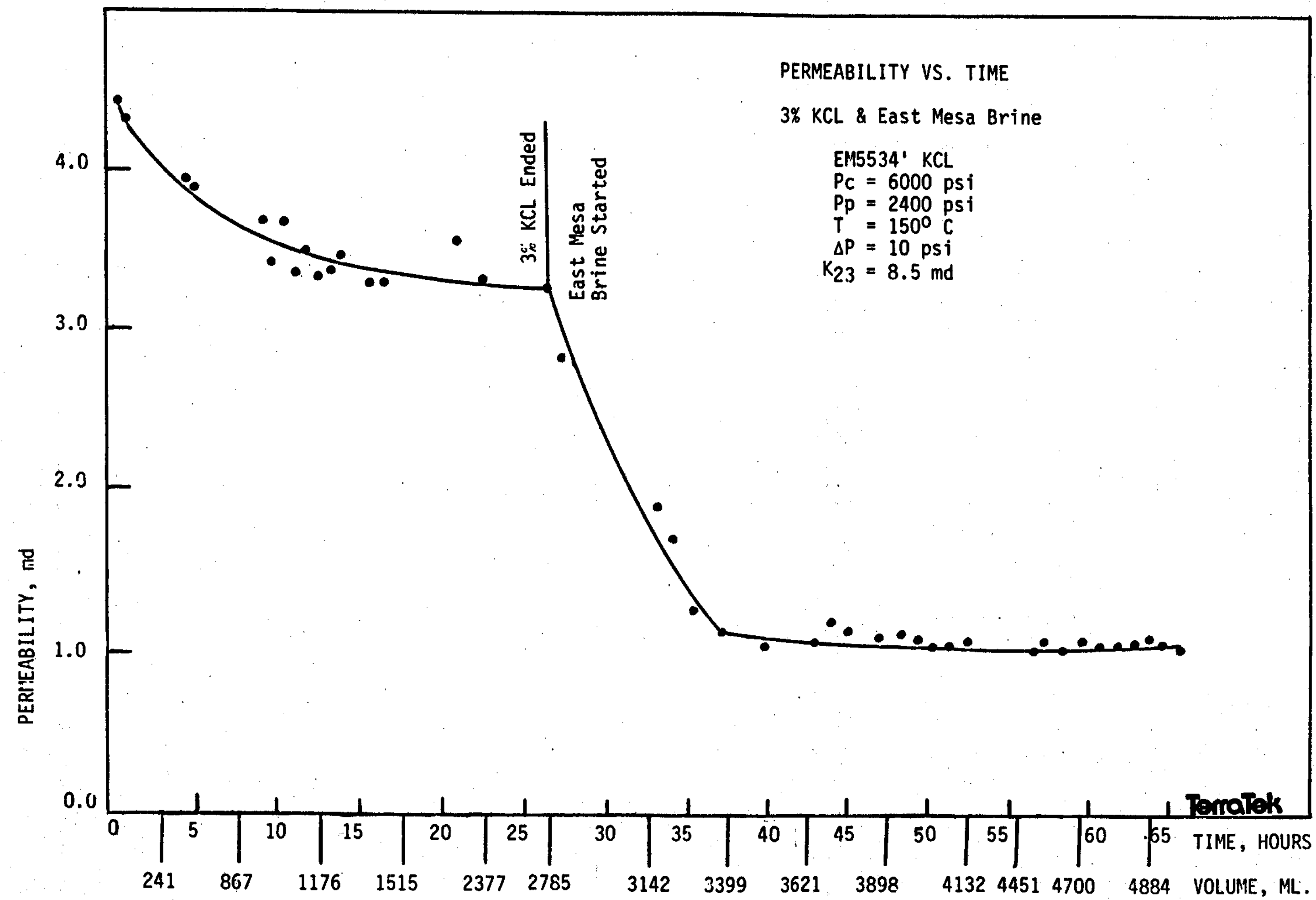

Figure 6: Permeability vs. Time
High to Low Salinity Contrast

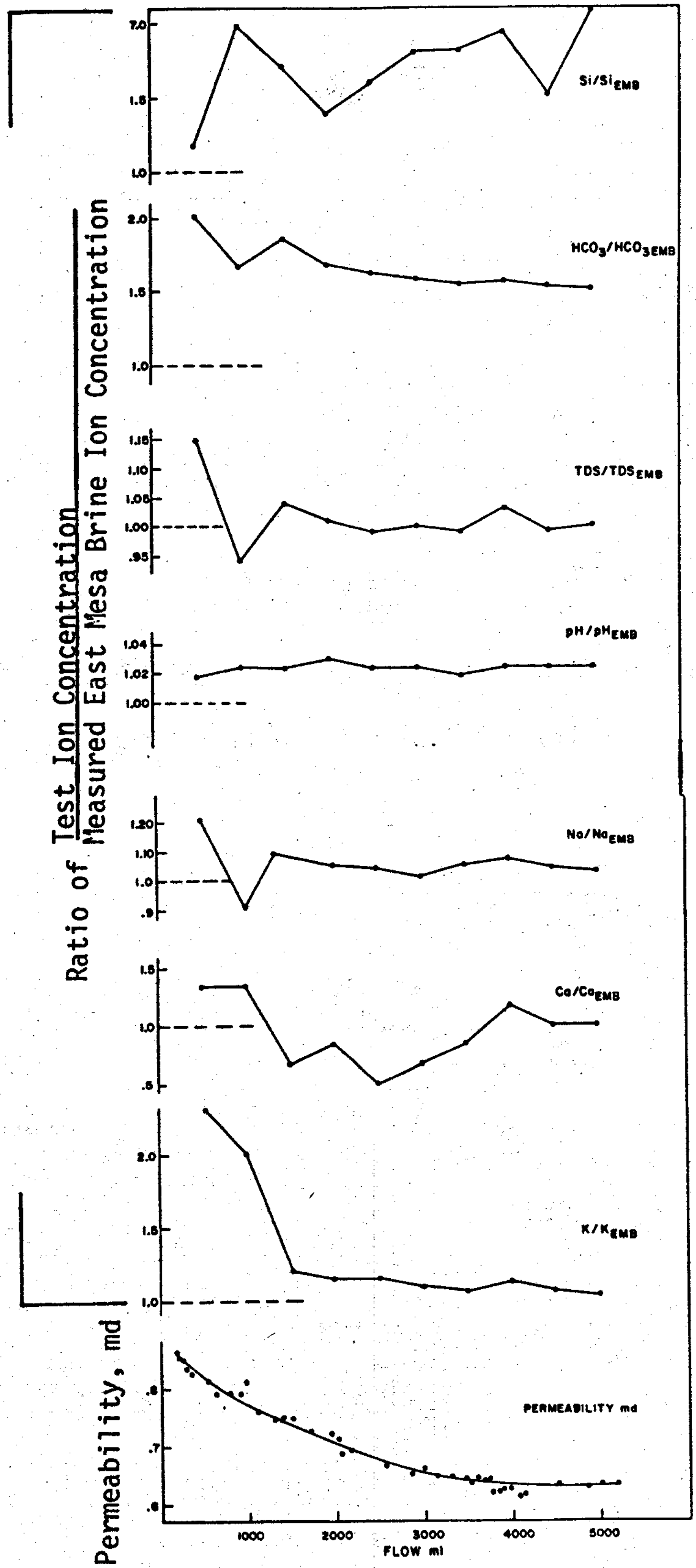

Figure 7: Effluent Ion Concentration vs. Cumulative Flow

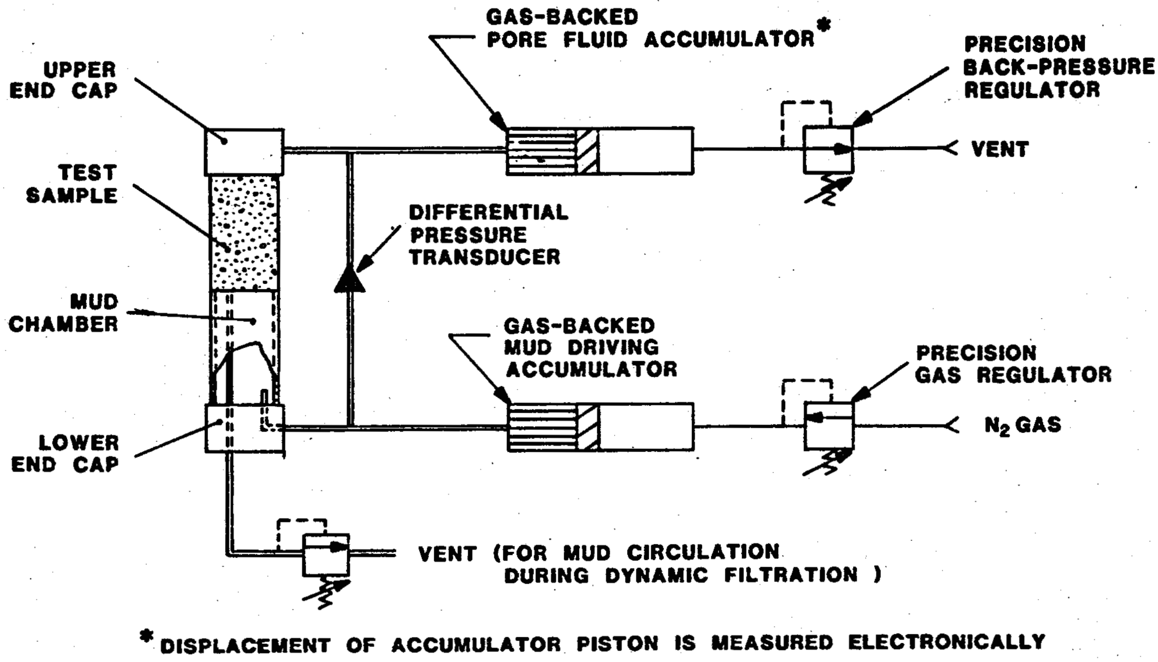

Figure 8 Simplified flow schematic.

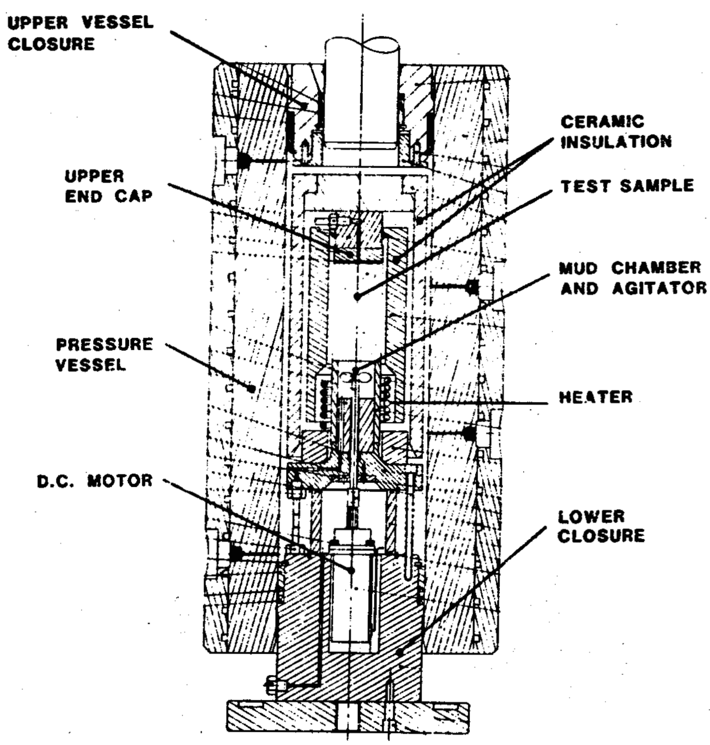

Figure 9 Formation damage vessel components.