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DRILLING FLUID/FORMATION INTERACTION AT
SIMULATED *IN SITU* GEOTHERMAL CONDITIONS:
FINAL REPORT

MASTER

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Prepared by Sandia Laboratories, Albuquerque, New Mexico 87185
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ABSTRACT

Interaction of drilling fluids with a geothermal reservoir formation can result in significant permeability impairment and therefore reduced well productivity. This interaction is studied under simulated *in situ* geothermal conditions of overburden stress, pore fluid pressure, temperature, and pore fluid chemistry. Permeability impairment of an East Mesa KGRA reservoir material is evaluated as a function of stagnation time, drilling fluid, and temperature. Results indicate that all of these parameters contribute significantly to the magnitude and the reversibility of the impairment.

This work was performed under Sandia contract #13-9407. Contract period was 19 July 1979 to 30 September 1979.

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EXECUTIVE SUMMARY

Drill and mud solids deposited in a producing formation of a geothermal well can irreversibly damage the formation by permeability reduction¹. Field experiences in Imperial Valley have suggested that the "aging" of drilling mud deposition in a producing formation can have deleterious effects upon well productivity². The residence time of the "internal filter cake" (cake actually formed within the formation) after deposition and before backflow is termed the "stagnation time" and is investigated in this program. Permeability impairment was determined as a function of varying stagnation times, mud types and temperatures. This work was performed under Sandia contract #13-9407. Contract period was 19 July 1979 to 30 September 1979.

Samples were prepared from core taken from Republic Geothermal, Inc. well 78-30RD, East Mesa, Imperial Valley and saturated with brine representative of the *in situ* state. An initial (undamaged) permeability measurement was made on samples while at simulated *in situ* conditions including overburden pressure [34.5 MPa (5000 psi)], pore fluid pressure [14.9 MPa (2165 psi)] and temperature (to 200°C). All permeability measurements were made in the direction of backflow. Samples were then subjected to simulated "hot" mud circulation and stagnation times. Stagnation times varied from 12 to 48 hours. Following this "damage" sequence, permeability was measured again in the backflow direction and compared with the original value.

The following two drilling fluid systems were evaluated:

HTM-1: A high temperature drilling fluid formulated for Sandia Laboratories by Mudtech, Inc., Houston, Texas. Constituents per standard barrel (42 gallons) are:

- 5 lbs. Bentonite
- 15 lbs. Sepiolite
- 20 lbs. Brown Coal
- 2.5 lbs. Sodium Polyacrylate
- 2 lbs. Sodium Hydroxide

KCl Polymer: A drilling fluid formulated and used by Republic Geothermal in East Mesa California. Constituents per standard barrel (42 gallons) are:

- 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)

Temperatures were controlled at 100°C and 200°C (bentonite transformation temperature is approximately 150°C). Post-test analysis included scanning electron microscope examination studies.

Testing was performed at Terra Tek's high temperature, high pressure geothermal testing facility utilizing specialized mud circulation equipment.

Results

HTM-1: Extended time exposures at both 100°C and 200°C temperatures result in approximately linear decreases (~1.3 %/hr) in permeability ratio ($K_{final}/K_{initial}$). Significant permeability impairment occurs at early times at the 100°C temperature. Higher temperature exposures result in less permeability impairment than the lower (100°C) exposure.

On the basis of this data, it is hypothesized that the increased impairment in this drilling fluid/formation interaction is a result of the bentonite (sodium montmorillonite) content of the drilling fluid.

Exposure temperatures bracket the transformation temperature of the montmorillonite clays (100-200°C). In the 100°C tests, the colloidal clays are being placed within the sample in their original form. At 200°C the clays have undergone a transformation (dehydration)* and are placed within the sample in an altered state³. Permeability impairment due to drilling fluid/rock interactions appears to be sensitive to the nature of the invading clays.

KCl Polymer: Permeability ratio ($K_{\text{final}}/K_{\text{initial}}$) of reservoir materials exposed to this drilling fluid system are very strongly a function of stagnation time. Lower temperature exposures (100°C) at short stagnation times cause a very dramatic permeability impairment evidenced by a permeability ratio approaching zero. With increasing time at the 100°C temperature, the permeability ratio demonstrates a considerable increase. At 200°C permeability ratio changes are much less and appear to be linearly decreasing at approximately 1.8%/hr.

The mechanism for this time dependent phenomena has not yet been determined and further core analysis including electron microscopy (SEM) and x-ray diffraction (XRD) is planned. It is suspected the degradational characteristics of the polymer play a key role since they are both time and temperature dependent.

* On heating to 200°C, montmorillonite clays lose their interlamellar water, reversibly, and the basal spacing shifts from between 12 and 15 angstroms to about 10 angstroms.

INTRODUCTION

"Formation damage" occurs when drilling mud invades the formation and causes a reduction of permeability at the wellbore/formation interface. Although mud invasion and damage occur with all muds during drilling when the mud column pressure is greater than formation pressure (by their nature*), it is important that efforts be made to minimize the detrimental effects. In any well, the principal detrimental effect would be a near wellbore formation permeability reduction. In a geothermal well this permeability reduction can be due to one or any combination of (a) solids plugging, (b) precipitate formation, and (c) matrix/filtrate interaction.

Hydrothermal wells are particularly susceptible to formation damage from drilling operations². The high temperature and chemically complex formation fluids may enhance the damaging aspects of any drilling or work-over fluid invasion in geothermal wells. Petroleum researchers have investigated various aspects of low temperature exposures (relative to geothermal wells) of reservoir rock to common petroleum drilling mud systems. These investigations provide the basis for investigations into geothermal formation damage in matrix permeability systems. However, these conclusions cannot be extrapolated to the much higher temperatures encountered in geothermal drilling. Moreover, such extrapolation to the geothermal environment is not advisable because geothermal formations (a) are often fracture dominated, (b) contain extremely chemically complex fluids and (c) are often lithologically dissimilar to those encountered in oil and gas reservoirs.

* A detailed discussion is contained in Appendix A.

Field experiences in Imperial Valley have suggested that the "aging" (time in place) of drilling fluid deposition in a producing formation can have deleterious effects upon well productivity. The residence time of the "internal filter cake"*, after deposition and before backflow, is termed the "stagnation time" and is investigated in this program. Permeability impairment in East Mesa, Imperial Valley core material is determined as a function of varying "stagnation times", drilling fluids, and temperatures. Testing in this program is conducted at simulated *in situ* geothermal conditions of overburden pressure, pore fluid pressure, temperature and pore fluid chemistry.

* Two filter cakes are actually generated during the drilling process, an inner cake and wellbore cake. The inner cake actually forms within the formation pore space and is generated prior to the wellbore cake.

Drilling Fluid Type

High bottomhole temperatures ($>150^{\circ}\text{C}$) encountered in geothermal drilling preclude the use of conventional bentonite based oil and gas drilling fluid systems. Bentonite drilling fluid systems undergo excessive thermal degradation, resulting in drastically increased viscosity and gelling when exposed to high temperatures. Special drilling fluid formulations are therefore required to cope with the high temperatures and circulation requirements of a geothermal well. Two such drilling fluids were selected for this testing program primarily because of availability* and secondarily because they represent major generic types of drilling fluids (modified clay systems and salt-polymer systems).

HTM-1: High Temperature Mud-1 (HTM-1) was formulated by Maurer Engineering, Inc. (Houston, Texas) for Sandia Laboratories⁴ and is designed to retain critical rheological properties at elevated temperatures.

The constituents (per standard barrel) of HTM-1 are:

Bentonite	5.0 lbs.
Sepiolite	15.0 lbs.
Brown Coal**	20.0 lbs.
Sodium Polyacrylate	2.5 lbs.
Sodium Hydroxide	2.0 lbs.

The major departure from conventional petroleum well drilling fluids is the substitution of sepiolite for bentonite in a 3:1 ratio. Sepiolite clay, part of the magnesium silicates group, has a rod-like structure quite unlike the plate-like structure of bentonite (sodium montmorillonite).

* Field mixes of these mud systems were desired but unavailable because of the lack of current drilling during the span of this contract.

** Particles present in the bulk brown coal ranged from sub-micron to 0.5 cm in diameter. An arbitrary particle size cut was made discarding particles greater than 100 microns. Particles of this size and larger make no contribution in the bridging process(1).

While the sepiolite structure is conducive to poor filtration control properties the addition of small amounts of bentonite is effective in maintaining filtration control. Brown coal and sodium polyacrylate are also added to help in controlling the filtrate loss of HTM-1.

Laboratory testing⁴ of this drilling fluid system has demonstrated its ability to maintain desirable rheological properties after extended exposures to 250°C (~500°F) temperatures. On the basis of this testing, it is anticipated that this formulation will not demonstrate the high shear strength and viscosity associated with bentonite drilling fluid systems at elevated temperatures⁴.

KCl Polymer: The KCl polymer drilling fluid system used in this testing was formulated and prepared by Chromally Delta Mud Co. (Houma, Louisiana) and has been used by Republic Geothermal, Inc. in East Mesa, California.

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 buffer⁹. Corrosion control is maintained by the addition of sodium sulfite (oxygen scavenger) and sodium hydroxide (pH control).

Characteristics of this drilling fluid at temperatures in excess of 200°C are not available.

Test Temperatures

Temperatures for this testing were chosen to be 100°C (212°F) and 200°C (392°F). These two temperatures represent reasonable approximation of downhole circulation temperatures encountered in typical geothermal drilling. Additionally these temperatures bracket the transformation temperature of the bentonite clays (sodium montmorillonite) present within the modified clay drilling fluid system.

Constant Parameters

In situ conditions representative of the East Mesa, KGRA were maintained constant throughout the testing. These conditions are summarized as follows:

Overburden Stress:	34.5 MPa (5000 psi)
Pore Fluid Pressure:	13.8 MPa (2000 psi)

Differential Pressure: 1.4 MPa (2000 psi)*
(Drilling Fluid)

Differential Pressure: 0.3 MPa (50 psi)**
(Permeability)

Brine used in this testing is formulated to be typical based upon water quality reports of several East Mesa wells⁵. This brine formulation has the following major ionic constituents:

HCO_3^-	700 ppm
Na^+	630 ppm
Cl^-	365 ppm
SiO_2^-	180 ppm
SO_4^{2-}	165 ppm
K^+	30 ppm
Ca^{2+}	10 ppm
F^-	4 ppm
B	<u>2 ppm</u>
Total Dissolved Solids (TDS)	2,086 ppm

Because of the relatively low concentration of total dissolved solids, the viscosity behavior of this brine with temperature was assumed to be the same as pure water. This has been shown to be a good assumption based upon recent work by Potter⁶.

* Constant driving differential pressure maintained in the direction opposite of backflow during the filtration of the drilling fluids.

** Constant driving differential pressure maintained to establish backflow during initial and final permeability. This pressure was maintained constant throughout the permeability testing.

PROGRAM OBJECTIVES

Permeability impairment in a matrix permeability geothermal reservoir material is determined at simulated *in situ* conditions as a function of the following variables:

- "Stagnation Time"
- Drilling Fluid Type
- Temperature

Permeability Impairment

Virgin (undamaged) permeability data is obtained for the core material tested prior to exposure of the core to drilling fluid. Following such exposure, permeability is again measured and compared to the virgin value in the form of a permeability ratio, $K_{\text{final}}/K_{\text{initial}}$. Permeability measurements are performed with the sample at simulated *in situ* conditions of overburden stress, pore fluid pressure, temperature and pore fluid chemistry. Flow is in the direction opposite to the invading drilling fluid.

"Stagnation Time"

The residence time of the "internal filter" cake after deposition and before backflow is termed the stagnation time. This time period simulates the field condition of a stagnant mud column standing in a geothermal well prior to backflow or during well testing. It has been suspected because of field experiences that this "aging" in place has detrimental effects upon the well's productivity.

FACILITIES DESCRIPTION

Testing for this program was performed at Terra Tek's geothermal testing facility, Figure 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 4.5×10^6 N (10^6 lbs)
- Sample size: 5 cm (2") diameter (to 535°C)
10 cm (4") diameter (to 200°C)

Figure 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 2, this flow cart provides pore pressure, differential pressure and constant monitoring of filtrate and drilling fluid volumes.

Figure 2. Photograph of drilling fluid circulation equipment.

RESERVOIR MATERIAL DESCRIPTION

Location

The Imperial Valley of California, located south of the Salton Sea, forms part of the Salton Structural Trough. This northwestward trending valley is part of a Tertiary aged sedimentary basin that is geologically active as evidenced by the considerable faulting in this region. The Colorado River Delta is the primary source of the sandstones, siltstones and clays that comprise the sediments of the Imperial Valley⁷. Located in the eastern part of the Imperial Valley is the East Mesa KGRA (see Figure 3).

Three stratigraphic units have been identified as comprising the basin: 1) A lower sequence of mainly nonmarine sedimentary rocks of early to middle Tertiary age dominate the basal unit which unconformably overlies pre-Tertiary metamorphic and igneous rocks. This basal unit also includes some volcanics and minor amounts of marine sedimentary rocks. 2) The marine Imperial formation of Pliocene age comprises the bulk of the middle sequence. 3) The upper sequence consists predominately of nonmarine deposits of late Tertiary and Quarternary age, mainly from the Colorado River drainage area⁸.

Sample Description

Core material was obtained* from two zones of Republic Geothermal, Inc., well 78-30RD located in the East Mesa, KGRA. The materials retrieved

* Materials were retrieved as a portion of a separate 1978 DOE Geothermal Rock Properties contract.

were from an intermediate sand, 1830 m (5500 ft) and a deep sand, 2200 m (7218 ft). Lithologic descriptions of these two zones are as follows:

1. Intermediate sand: gray-brownish, very fine to medium grained angular to subrounded, poorly to moderately well sorted, slightly friable, slightly calcareous.
2. Deep sand: gray-brownish, fine grained, angular to subrounded, medium hard, well sorted with some silica and calcareous cement.

Mineralogical and physical property data for these intervals is shown in Tables 1 and 2.

Figure 3. KGRA of Imperial Valley, California.

TABLE 1
Mineralogical Analysis -- East Mesa Samples⁹

Republic Geothermal East Mesa Well #	Depth (feet)	Grains (% of total)											Matrix (% of total)				Cement (% of total)			Porosity (% of Total)	Roundness (Powers, 1953)	Sorting	Quartz Overgrowth (yes or no)	Mean Grain Diameter (mm)	Classification
		Undulose Qtz.	Non-Undulose Qtz.	Composite Qtz.	Plagioclase	Orthoclase	Microcline	Biotite	Muscovite	R.F. Chert	R. F. Shale	Epidote	Clay Minerals	Pyrite	Hematite	Organic Matter	Calcite	Silica	Hematite						
78-30	5503	75	-	-	2	-	1	T	T	2	-	T	6	-	1	-	3	5	-	5	Angular to Subangular	Mod. Well	Yes	.098	Very fine grained sandstone
78-30	5513	68	-	1	8	1	3	-	T	1	-	T	4	-	1	-	2	8	-	3	Subangular to Subrounded	Poorly	Yes	.150	Fine grained sandstone
78-30	5526	5	-	1	10	1	2	T	T	2	-	T	5	-	1	-	1	6	-	7	Subangular to Subrounded	Poorly	Yes	.200	Fine grained sandstone
78-30	5533	65	-	2	1	-	3	-	T	4	T	T	3	-	T	-	2	8	-	12	Subrounded to Rounded	Mod. Well	Yes	.390	Medium grained sandstone
78-30	5560	62	-	3	4	T	T	T	-	6	-	2	2	-	1	-	2	8	-	10	Subangular to Rounded	Poorly	Yes	.300	Medium grained sandstone
78-30	7148	64	-	3	5	-	1	T	T	8	-	T	6	-	T	-	1	3	-	9	Angular to Subangular	Mod. Well	Yes	.150	Fine grained sandstone
78-30	7151	68	-	2	3	1	3	T	T	7	-	T	5	-	T	-	1	3	-	7	Subangular to Subrounded	Mod. Well	No	.190	Fine grained sandstone

TABLE 2
Physical Property Data -- East Mesa Samples¹⁰

Sample (footage)	Interval	Density (gm/cc)			Total Porosity (%)
		As-Received*	Dry	Grain	
5530.0 } 5535.0 }	Intermediate Sand	2.19	2.05	2.75	25.2
7144.0		2.14	1.94	2.76	29.6
7148.0		2.08	1.88	2.74	31.3
7148.5		2.26	2.13	2.67	20.2
7149.0		2.29	2.16	2.63	18.0
7149.2		2.28	2.11	2.63	19.8
7149.6		2.23	2.09	2.62	20.1
7149.6		2.24	2.10	2.63	20.4
7150.0	Deep Sand	2.25	2.09	2.65	21.1
7151.0		2.28	2.18	2.57	15.1
7151.2		2.17	2.00	2.65	24.4
7151.5		2.22	2.08	2.62	20.6
7152.0		2.18	2.04	2.65	23.0
7154.0		2.12	1.95	2.72	28.4
7154.5		2.30	2.17	2.62	17.3
7155.0		2.18	2.03	2.75	26.3
7155.2		2.16	2.01	2.64	23.9
7155.5		2.21	2.03	2.65	23.4
7157.0		2.19	2.11	2.73	22.6
7157.5		2.21	2.07	2.63	21.3
7158.0		2.26	2.08	2.56	18.8
7159.5		2.25	2.09	2.64	20.9
7160.0		2.29	2.15	2.63	18.2

* Core was waxed and sealed at the drill site. This density was measured immediately upon unwrapping.

TEST PROCEDURES

Sample Preparation

Competent core sections of at least 10.16 cm (4 inches) in length were selected for sample preparation from the deep sand zone. Two solid cylinders of rock with diameters of 5.08 cm (2 inches) (test sample) and 2.54 cm (1 inch) (reference sample) were cored wet (tap water) and the ends sawed perpendicular such that the finished samples were 10.6 cm (4 inches) long. Both samples were re-wrapped in aluminum foil and sealed in beeswax for storage prior to testing*. The reference sample was prepared for post-test SEM comparison and physical property testing.

The test sample was jacketed for test temperatures of 100°C (212°F) or 200°C (392°F) using a teflon shim and thin silicone rubber (RTV) jacket applied to the sample surface. This prevents flow along the sides and isolates the internal pore fluid from the confining fluid. Sealing is further enhanced by the application of a heat shrink teflon jacket over the entire sample and stack assembly. Figure 4 contains a photograph of a test sample prepared in this manner.

Test Configuration

A simplified flow schematic of the test system is shown in Figure 5. The test sample is located immediately above a stainless steel cavity designated as the "mud chamber". This chamber and the lower face of the

* Core material retrieved was sealed at the well site to preserve water saturation. These procedures were designed to maintain water content and prevent possible alteration caused by drying of the core.

Figure 4. Photograph of prepared test sample.

* DISPLACEMENT OF ACCUMULATOR PISTON IS MEASURED ELECTRONICALLY

Figure 5. Simplified flow schematic.

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 stack is placed within the pressure vessel in the configuration of Figure 6. Heating to test temperature is accomplished by an internal heater with ceramic shrouds* acting as circulation aids. 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

Figure 6. Formation damage vessel components.

* For a more complete discussion of this technique see: Enniss, D. O., et al., "Capabilities to Measure Geothermal Material Properties at Simulated *In Situ* Conditions," Terra Tek Report TR 79-49.

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 $0.5^{\circ}\text{C}/\text{min}$. 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 head 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 (0.3 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 during which steady-state flow is achieved.

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 drilling fluid being evaluated.

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 13.8 MPa (2000 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 condition exists. To simulate downhole circulation, 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 and allows the generation of dynamically stable equilibrium filter cake. This dynamic filtration is continued for a period of two hours.

Stagnation begins with the discontinuation of the dynamic agitation and drilling fluid circulation. This stagnation or static filtration phase lasts 12 to 48 hours depending on the test parameters. 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 0.3 MPa (50 psi). Flow data recorded during this period is used to calculate the final permeability which is compared to the virgin value.

Post-Test Sample Analysis

Test samples are removed, photographed, sealed and preserved following each test. Filter cakes are also removed and stored. Comparisons of the damaged sample and material immediately adjacent are made upon selected samples under a scanning electron microscope.

RESULTS

Data Summary

A tabulated summary of the testing performed in this program is contained in Table 3. Data for both drilling fluid types are included.

Test designations appearing in this table are used in following data figures and therefore warrant explanation. For example:

HTM-1 Drilling Fluid

A graphical representation of permeability ratio ($K_{\text{final}}/K_{\text{initial}}$) versus stagnation time for the HTM-1 drilling fluid is contained in Figure 7. Extended time exposures (>12 hours) at both 100°C and 200°C temperatures result in approximately linear decreases (~1.3%/hour) in permeability ratio. Significant permeability impairment occurs at stagnation times of less than 12 hours at 100°C temperature. Note that the shape of the curve in this region is arbitrarily drawn. Higher temperature exposures (200°C) result in less permeability impairment than do the lower temperature (100°C) exposures.

On the basis of this data, it is hypothesized that the increased impairment in this drilling fluid/formation interaction is a result of

TABLE 3

Formation Damage Summary -- East Mesa Sandstone

Test	Core Designation	Drilling Fluid	Temp °C	Stagnation Time Hours	Initial Permeability md	Final Permeability md	K_f/K_i Ratio
HTM-112-1	RPG-7155'	HTM	100	12	.041	.021	.52
HTM-124-2	RPG-7151'	HTM	100	24	.256	.088	.34
HTM-148-3	RPG-7161'	HTM	100	48	1.102	.263	.24
HTM-212-4	RPG-7151'	HTM	200	12	.438	.410	.94
HTM-224-5	RPG-7159'	HTM	200	24	.051	.038	.75
HTM-248-6	RPG-7160'	HTM	200	48	.159	.083	.52
KC1-112-1	RPG-7162'	KC1	100	12	.116	.006	.06
KC1-124-2	RPG-7163'	KC1	100	24	.479	.006	.01
KC1-148-3	RPG-7144'	KC1	100	48	.035	.019	.54
KC1-212-4	RPG-7163'	KC1	200	12	.120	.086	.72
KC1-224-5	RPG-7164'	KC1	200	24	.521	.299	.58
KC1-248-6	RPG-7145'	KC1	200	48	.058	*	---

*Jacket failure, test aborted.

Figure 7. HTM-1; permeability ratio versus stagnation time.

the bentonite content of the drilling fluid. Exposure temperatures bracket the transformation temperature of the montmorillonite clays (~150-175°C). In the 100°C situation, the clays are being placed within the sample in their original form. At 200°C the clays have undergone a transformation to illite, a more dehydrated clay structure, and are placed within the sample in this altered state. Clay/rock interaction during the internal filter cake formation appears to be sensitive to the nature of the invading clays.

Dynamic filtration data for the HTM-1 tests are contained in Figure 8. Filtrate volume in milliliters (10^{-3} liters) is plotted versus $\sqrt{\text{time}}$ (minutes^{1/2}). Conventional filtration theory¹¹ predicts that filtrate loss should be proportional to the square root of time, $\sqrt{\text{time}}$. The non-linearity of these filtration curves suggest that this conventional theory is not followed in the HTM-1 drilling fluids. Also, filtration loss does not correlate with initial sample permeability; that is, large initial permeabilities do not result in large filtrate losses. For example, the test showing the largest filtrate loss during dynamic filtration with this fluid was HTM-224-5 with an initial permeability of 50 μ darcies (10^{-6} darcy). Only one other HTM-1 test sample had a lower permeability, HTM-112-1 (40 μ darcies). Clearly the filter cake permeability is the dominant factor controlling filtrate loss. The sample having the largest permeability of those tested, HTM-148-3 (1.1 md) demonstrates the closest approximation to the proportionality with time suggested by the conventional filtration theory.

Figure 8. HTM-1; dynamic filtration.

Total filtration volumes (dynamic and static filtration) versus time are shown in Figure 9. Cumulative filtrate volumes are not directly comparable due to the variation in permeability and temperature of the test samples. This figure, however, does give an indication of the total amount of filtrate handled by the test sample. The pore volume of a typical test sample is on the order of 40 ml to 60 ml (20-30% porosity). Tests HTM-224-5 and HTM-248-6 would have likely displaced the original pore fluid with drilling fluid filtrate, assuming significant channeling does not occur in the samples.

Figure 9. HTM-1; total filtration volumes.

The rate of filtrate loss through the core is governed by both the permeability of the core and the filter cakes. Since these filtrations were conducted under constant pore and differential pressure, variations due to compressibility can be ignored. Impedance to filtrate flow through the filter cake and the sample is best represented as the sum of these respective impedances or:

$$R_{\text{total}} = R_{\text{filter cake}} + R_{\text{sample}}$$

The filter cake "flow impedance" can be determined* as a function of time and is shown for the HTM-1 drilling fluid in Figure 10. Impedance to filtrate flow is clearly dependent upon temperature. Low temperature filtrations result in impedances that are significantly higher than those produced by higher temperature filtrations. This is consistent with the transformational characteristics of the bentonite clay constituent.

KCl-Polymer Drilling Fluid

Permeability ratio ($K_{\text{final}}/K_{\text{initial}}$) of reservoir materials exposed to this drilling fluid system are very strongly a function of stagnation time. Permeability ratio versus stagnation time for the KCl-polymer system is shown in Figure 11. Lower temperature exposures (100°C) cause very dramatic permeability impairment at stagnation times of less than 12 hours. The permeability ratio at 12 hours stagnation time is essentially zero. The curve connecting 0 hours and 12 hours stagnation has been arbitrarily drawn. With increasing time at the 100°C temperature the permeability ratio demonstrates a considerable increase to approximately 0.50 at 48 hours. At the higher temperature, 200°C, permeability ratio changes are much less and appear to be linearly decreasing at a rate of approximately 1.8%/hour.

It is significant to note that the two test temperatures bracket the maximum recommended use temperature of the polymer system. It is suspected that the degradational characteristics of the polymer play a key role in the differing temperature dependence.

* A complete detailed description of the model used in this determination is contained in Appendix B.

Figure 10. HTM-1; flow impedance of filter cake versus total filtration time.

Figure 11. KCl-Polymer; permeability ratio versus stagnation time.

Dynamic filtration data for the KCl-polymer tests are contained in Figure 12. Filtration of this drilling fluid system behaves much closer to that predicted by conventional filtration theory. Tests KCL-224-5 and KCL-112-1 demonstrate very linear regions and excellent agreement to the proportionality with the square root of time predicted. Again, as with the HTM-1 drilling fluid, initial permeability does not correlate with filtrate loss. The dominant permeability in the system is clearly the permeability of the filter cakes.

Figure 12. KCl-Polymer; dynamic filtration.

Total filtration volumes (dynamic and static) versus time are contained in Figure 13. Again, accumulative volumes are not directly comparable. However the magnitude of filtrate loss in the KCl-polymer system is significantly higher than the HTM-1 system. Maximum volume handled in the HTM-1 system was 60 ml, in the KCl-polymer system, 200 ml. Clearly in all KCl-polymer tests the pore fluid volume was displaced by the invading filtrate. Filter cake "flow impedance" for the KCl-polymer system is shown as a function of time in Figure 14. Flow impedance demonstrates temperature dependence with higher temperature filtrations resulting in lower flow impedance. This is consistent with the higher filtration volumes observed in the 200°C testing and with the basic temperature dependent degradational characteristics of the polymer.

SEM Analysis

A number of tested and untested samples were examined under a scanning electron microscope. The results of such an examination are at best qualitative given the alteration inevitable with dehydration and sample coating. Figures 15 and 16 are typical photographs obtained for the HTM testing. In a qualitative sense, much more open porosity was visible in the untested samples; clays are present but in generally small amounts. Post-tested samples exhibited considerably less visible pore channels and as can be seen from Figure 16, clays deposited from the drilling fluids are clearly visible. It was not possible in the samples observed to determine the depth of clay penetration.

Figure 13. KCl-Polymer; total filtration volumes.

Figure 14. KCl-Polymer; flow impedance of filter cake versus total filtration time.

5 microns

Figure 15. HTM-1 test sample not exposed to filtration (magnification 1330X).

5 microns

Figure 16. HTM-1 test sample following completed test cycle (magnification 1150X).

Figures 17 and 18 similarly contain typical comparison photographs of the KCl-polymer test samples. Open porosity was clearly visible in both the untested and tested samples. Significant clay migration (of *in situ* clays) was not observed. Crystalline precipitation of KCl was observed in pore space but most likely occurred during sample preparation for the SEM analysis.

In the limited SEM effort employed it was not possible to isolate and identify quantities of polymer. Because of this, it was not possible to determine the depth of polymer invasion.

10 microns

Figure 17. KCl-polymer test sample following completed test cycle (magnification 630X).

1 micron

Figure 18. KCl-polymer test sample close-up of KCl precipitation in pore area (magnification 6200X).

CONCLUSIONS

HTM-1 Drilling Fluid

Permeability impairment resulting from interaction of this drilling fluid with a matrix permeability sample is time dependent. Decreases on the order of 1.3% per hour are encountered with lower temperature exposures resulting in significant early time impairment. Higher temperature exposures (200°C) result in lower overall impairment. The transformation of the 25% bentonite clay constituent is the most probable mechanism involved in this temperature dependence. Clay/rock interaction is sensitive to the structural nature of the invading clay. Transformation of the sepiolite constituent (75% clay component) into a platelet (from a rod-like structure) can begin at the 200°C temperature¹². Whether this transformation can occur at a sufficient rate to play a role in altering the bridging phenomenon in this system is presently unknown.

KCl-Polymer

Permeability impairment due to exposure of matrix material to this drilling fluid system is both temperature and time dependent. Drastic decreases in the permeability ratio during the lower temperature exposures were experienced. This ratio approached zero at 12 hours stagnation time. Because tests were not conducted at times shorter than this, the actual rate of decrease is not known but must exceed an average decrease of 8% per hour. Long stagnation times result in an increasing recovery of permeability at this same temperature. Higher temperature exposures

resulted in permeability ratios that were approximately linearly decreasing at 1.8% per hour.

Polymer degradation is both time and temperature dependent. Maximum recommended use temperature of this polymer system was exceeded during the 200°C testing. It is therefore suspected that this degradation is a contributing factor in the time and temperature dependence of this system. At the 200°C temperature, the polymer would have experienced substantial degradation prior to being placed within the pore space of the sample. The 100°C temperature testing is within the normal operating temperature range of this system and therefore the polymeric chains would be intact during the filtration. Although possibly aided by the moderate temperature, the degradation of the polymer would occur principally because of its instability with time.

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APPENDIX A

TECHNICAL DISCUSSION

MECHANISMS OF GEOTHERMAL FORMATION DAMAGE

The following discussion will address various recognized areas in which drilling fluid/formation interaction will result in formation damage. It is the intent of this section to point out the complexity of this problem and the limited extent to which high temperature and complex chemistry effects have been addressed.

For this discussion, the mechanisms of formation damage are divided into four major categories: filtrate induced damage, particle damage, operating technique induced damage, and fractured reservoir damage.

Filtrate Induced Damage

Salinity Contrast: The fluid composition of a geothermal resource is a complex interaction of a wide variety of solid and gaseous solutes. Equilibrium of the geothermal brine in the reservoir is both temperature and pressure dependent. When filtrate from the drilling mud displaces the formation fluid surrounding the wellbore, a "salinity contrast" exists that is potentially detrimental to the productivity of the well. Clay minerals contained in the formation pore spaces may be sensitive to ionic components in the filtrate and ion exchange can take place. Since hydrating clays significantly increase their volume, swelling that occurs in pore throat areas will cause permeability reductions. A more serious problem is encountered when these swelling clays become detached from the pore walls and become dispersed in the pore fluid causing effective blockage of flow paths.

The two major factors in the hydrating process are the clay type present and the ionic composition of the invading filtrate. Clays are cation-exchange materials and the nature of the clay cations will determine the response to the filtrate. By altering the ionic chemistry of the invading filtrate to contain a preferentially adsorbed cation, the clays can be stabilized^{A1}. Jones^{A2} has demonstrated the effectiveness of this technique in oil field application. However, this work was confined to low temperature (23°C) behavior. Clays present in geothermal systems will exist in various stages of metamorphism due to the percolation of high temperature and chemically complex brines. Physical and chemical responses of these clays to non-equilibrium invading fluids are not known.

Exposure Rate: Research has shown that permeability blockage due to clay sensitivity is also dependent upon the rate of contrast exposure^{A2}. Rapid exposure results in more permeability reduction than slow exposure. Past work is limited to the room temperature condition and the 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 utilizing scanning electron microscope (SEM) techniques have demonstrated this effect on clay particle disturbances in sandstones. Clay mobility within the pore space was shown to increase with increasing pore fluid pH^{A3}. 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: Formation fluids in geothermal situations may contain particular anions and cations which when placed in contact with ionic constituents in the filtrate will cause insoluble precipitates. For example, some formation fluids in the Imperial Valley contain free barium. Sulfates in the makeup water of the drilling fluids or chemical additives, result in an insoluble precipitate, barium sulfate, being formed in the pore channels causing a permeability reduction^{A4}.

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

Particle Damage

Particle Size: During the internal filter cake generation, both mud solids and filtrate enter the formation. Clay solids and drilling solids present in the mud that are smaller than the pore openings will be deposited at various pore throats within the formation. As these particles accumulate at the pore throats, successively smaller particles are "filtered" out. Eventually an internal filter cake is formed and greatly reduces further penetration into the formation by mud solids. Filtrates, containing water and various chemicals, although inhibited, can migrate through this "cake" and this constitutes the fluid loss

to the formation. Depth of invasion and the magnitude of particle damage can be controlled to a certain extent by designing the mud to include specifically sized particles, termed bridging particles.

Abrams^{A5} 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. The extent to which Abrams' data applies at higher temperatures is not obvious.

Particle Size Distribution: As discussed in the previous section, particle size is significant in the bridging process. Due to the impacts and shearing nature of the flow through the annulus, pumps and bit nozzles, particles present in the muds will continually degrade into smaller particle sizes. Specific particle sizes are very difficult (if not impossible) to obtain in the 2-10 micron (10^{-6} meters) size generally required for bridging in matrix formations. Particle distributions will be obtained from the grinding or mill processing of the added bridging particles (assuming that additional particles other than drill solids are added). It is therefore desirable to know which ranges of particles will adequately bridge and which will adversely contribute to the formation damage. Solids removal equipment on the rig can effectively remove solids down to the 2 micron (10^{-6} meters) range.

Drilling solids present in the muds have been demonstrated to reduce penetration rates and thereby increase rig costs. It is therefore desirable to remove as much of these drill solids as possible and still maintain adequate bridging while penetrating the producing formation. The range in particles remaining and the subsequent temperature and chemical influences require documentation. Previous research work focused entirely upon matrix permeability type formations; the influence of fractures, or combinations of matrix and fracture permeability and the subsequent particle sizes or ranges required for bridging has not been determined.

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 might "unlock" and clear the throat obstruction.

Operating Technique Induced Damage

Stagnation Time: During the drilling process there will be times when the mud will stand in the wellbore, particularly upon completion prior to backflow. This column of "stagnant" mud can have adverse effects upon the ultimate productivity of the well. "Stagnation times"

allow the internal filter cake to remain in place and age. Although bottomhole temperature recovery does not appear to play a significant role^{A6}, the time in place appears to have deleterious effects upon recovered permeability.

Backflow Times: Backflow of the formation into the wellbore is presently the only viable method of removing (or partially removing) the internal filter cake in geothermal wells. Recovered permeabilities in some matrix dominated materials have indicated that recovery permeability is time dependent^{A3}. Some additional studies have indicated that recovered permeability can depend upon the rate at which backflow is initiated, suggesting that higher permeabilities are obtained when the backflowing process is initiated slowly. Temperature and aging influences upon this phenomenon are not yet known.

The slotted liner geothermal well completion technique greatly enhances the possibility of formation damage. The slotted liner, which is run in the well prior to displacing the drilling fluid from the hole, entraps mud and mud cake. Even though the mud inside the slotted liner is displaced, the stagnate trapped mud in the liner-wellbore annulus remains until the well is produced. Economical, high temperature chemical flushes capable of removing these entrapped materials are not currently available. Not only are the chemicals not effective, but the slotted liner (or open hole completion) limits placement capability.

Fractured Reservoir Damage

The diversity in resource type is clearly a unique trademark of geothermal systems. Table A1 summarizes the reservoir type of some major active geothermal resource areas under development in the continental United States.

TABLE A1
KGRA Reservoir Types

Resource	Reservoir Type
Geysers	Fracture-Dominated*
East Mesa Valley	Matrix-Dominated
Salton Sea	Combined Matrix-Fracture
Northern Nevada	Fracture-Dominated
Milford, Utah	Fracture-Dominated
Valles Caldera	Combined Matrix-Fracture

* Unique under-pressured system requiring special techniques (air drilling).

As shown, a majority of the reservoir systems are fractured, occurring in a host rock of relatively low permeability. The large production potential of the matrix dominated Imperial Valley resource justifies its attention in addition to addressing the fracture dominated systems. The formation damaging aspects of the drilling process will not be the same for the two types of reservoir rock (i.e. fracture or matrix permeability).

As pointed out earlier, the bulk of the formation damage research had been focused upon low temperature and matrix permeability type materials typically encountered in oil field applications. In such applications, fractures intersected during drilling represent potential lost circulation difficulties and many techniques exist to effectively

seal them, permanently. Of course in geothermal situations, the fractures must be sealed during drilling (to prevent lost circulation) and then reopened upon completion and backflow. Fractures in rock represent very high permeability flow conduits and the failure to reopen these conduits can cause substantial reduction in the productivity of the resource.

The bridging mechanisms in fractures are not understood. It is important that the mechanisms be defined in order to minimize the amount of permanent deposition in the fracture and subsequent permeability reduction. Fractures which are not bridged at the wellbore interface will essentially "clog" and not "unclog" upon backflowing the well^{A7}.

Since naturally fractured formation materials are difficult to obtain, any laboratory investigation must simulate the fracture formation. The nature (tortuosity and rugosity) of *in situ* fractures and their effective width is not easily known. Therefore, very careful analysis must be given to any laboratory simulation of this phenomena to ensure that data generated will be a useful tool to the drilling engineer confronted with a completion within a fractured geothermal formation.

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APPENDIX B

DISCUSSION OF FILTER CAKE FLOW IMPEDANCE DETERMINATION

For this discussion the test sample is modeled as:

Figure B1. Impedance model.

Impedance to filtrate flow through the filter cake and the sample is represented as a sum of the respective impedance of each element in series:

$$R_t = R_{\text{ext. filter cake}} + R_{\text{internal filter cake}} + R_{\text{sample}} \quad (1)$$

Fluid flow impedance can be modeled from an electrical analog

$$E = IR \text{ (ohm's law)} \quad (2)$$

Voltage (E) is analogous to pressure differential (ΔP). Current (I) is analogous to fluid flow rate (Q).

Permeability is calculated according to the Darcy law:

$$K = \frac{v_t}{v_r} \frac{Q_r \mu L}{A \Delta P} \quad (3)$$

where:

K = permeability, darcies

v_t, v_r = specific volume of fluid at temperature and at reference point, respectively, m^3/kg

Q_r = flow rate at reference point, ml/sec (measured at $T = 23^\circ C$, constant)

μ = viscosity at flow temperature, cp (temperature dependent)

L = sample length, cm

A = cross-sectional flow area, cm^2

ΔP = pressure differential, bars (absolute)

The specific volume ratio at the front of this equation constitutes a volumetric correction for fluid volume expansion at the flow temperature since flow rate measurements are made at a reference point with constant $23^\circ C$ temperature.

Rearrangement yields:

$$\frac{\Delta P}{Q} = \left(\frac{v_t}{v_r} \right) \left(\frac{\mu L}{K A} \right) = R \quad (4)$$

Substitution into (1):

$$R_{total} = (R_{ext. f.c.} + R_{int. f.c.}) + \left(\frac{\mu L}{K A} \frac{v_t}{v_r} \right)_{sample} \quad (5)$$

Sample values are based upon initial permeability of the test sample.

External and internal filter cakes effects are combined and not distinguishable in this analysis, therefore:

$$R_{f.c.} = R_{total} - \left[\frac{v_t \mu L}{v_r K A} \right]_{sample}$$

$$R_{total} = \left(\frac{\Delta P}{Q} \right)_{filtration}$$

$$R_{f.c.} = \left(\frac{\Delta P}{Q} \right)_{filtration} - \left[\frac{v_t \mu L}{v_r K A} \right]_{sample} \quad (6)$$

$Q_{filtration}$ is a time dependent variable which was experimentally determined, as was the permeability of the sample, K . All other variables are known or controlled.

Distribution:
TID-4500-R66 UC-66c (752)

400 C. Winter
1000 G. A. Fowler
1100 C. D. Broyles
1130 H. E. Viney
2000 E. D. Reed
2300 J. C. King
2320 K. Gillespie
2325 R. E. Fox
2328 J. H. Barnette
2500 J. C. Crawford
2513 W. B. Leslie
4000 A. Narath
4200 G. Yonas
4300 R. L. Peurifoy, Jr.
4400 A. W. Snyder
4443 P. Yarrington
4500 E. H. Beckner
4700 J. H. Scott
4710 G. E. Brandvold
4720 V. L. Dugan
4730 H. M. Stoller
4740 R. K. Traeger
4741 S. G. Varnado (25)
4742 A. F. Veneruso
4743 H. C. Hardee
4744 H. M. Dodd
4744 C. C. Carson
4745 J. R. Tillerson
4745 T. E. Hinkebein
5000 J. K. Galt
5510 D. B. Hayes
5512 D. F. McVey
5512 A. Ortega
5530 W. Herrmann
5532 B. M. Butcher
5533 J. M. McGlaun
5600 D. B. Schuster
5620 M. M. Newsom
5800 R. S. Claassen
5810 R. G. Kepler
5812 C. J. M. Northrup, Jr.
5812 B. T. Kenna
5813 P. B. Rand
5830 M. J. Davis
5831 N. J. Magnani
5832 R. W. Rohde
5832 R. J. Salzbrenner
5833 J. L. Ledman
5833 J. L. Jellison
3141 T. L. Werner (5)
3151 W. L. Garner (3)
8266 E. A. Aas