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HALLIBURTON ENERGY SERVICES

DUNCAN TECHNOLOGY CENTER - DUNCAN, OKLAHOMA
A HALLIBURTON COMPANY

STIMULATION APPLICATIONS

PROJECT REPORT

To: Mr. S. Fross
Anadarko Petroleum Corporation
Liberal, Kansas

SAA-A057-94

December 28, 1994

Title: **Formation Compatibility Study**

Prepared by: F. R. Behenna

WELL DATA

Well Name: Boekhaus Trust "A" No. 1
Field: Hugoton
Location: Morton, Co. KS
Depth: 2181.35 ft - 2194.00 ft
Date Received: November 12, 1994

PURPOSE

The purpose of this project was to conduct special core testing on several submitted core plugs from the Boekhaus Trust "A" No. 1 well located in the Hugoton Field in Morton, Co. Kansas. Testing was conducted at the request of Anadarko Petroleum Corporation to address concerns regarding the compatibility of completion fluids used on the reservoir rock in wells in this area. Two specific concerns were addressed: the compatibility of non-acid fluids used in the course of fracturing treatments on this formation and the compatibility of acid treating fluids used for perforation breakdown prior to fracturing treatments.

PURPOSE (Cont'd)

The primary concern as to the compatibility of the non-acid fluids with the formation is whether adequate control over clay swelling and migration is being achieved with the fluids currently used to treat the wells. In some formations, contact with fresh water or water of insufficient salinity can induce severe permeability loss as clay particles either swell within pore spaces or become mobile and bridge in pore throats of the formation. The susceptibility of a formation to such potential damage is a function both of the formation mineralogy and the composition of the formation brine.

Testing involving acids focused on determining the permeability response to two different strengths of Fe acid (HCl + iron chelating agents) and the amount of iron liberated during the acidizing process. In some cases large amounts of iron can be liberated during acidization depending on formation mineralogy and the location within the rock matrix of any iron bearing minerals. If such iron is present in the Fe^{+3} state it will precipitate in spent acid. This can potentially cause permeability reduction in the formation.

Testing for this study is broken into three areas:

1. *Determination of formation mineralogy, solubility and iron content*
2. *Non-Acid Core Flow Tests*
3. *Acid Core Flow Tests*

CONCLUSIONS

1. Formation mineralogy over the interval examined did not show considerable variation for the most part. Clay minerals made up approximately 5% of the total sample mass, with illite being the predominant clay type present. While several of the samples had a reddish-brown color, hematite was detected in only one sample that contained a large volume of shaly material. Both dolomite and hematite are probably localized to this shaly material to a large degree where little contact with treating fluids will occur.

2. Core flow tests with potential fracturing base fluids indicated slight water sensitivity. Well performance after a hydraulic fracturing treatment in this type of formation is not greatly affected by permeability reduction at the fracture face unless the damage is severe. Since severe permeability reductions did not occur upon fresh water exposure in this formation, fresh water could be considered as a potential fracturing base fluid.

3. Both 15% and 7.5% Fe acid increased formation permeability slightly (20-30%). Neither appeared to cause any formation damage. Iron levels in the acid effluent were surprisingly low, and fell well below the concentrations of iron which Fe acid is capable of chelating. The mass of iron leached from the core plugs by the 100 ml of acid injected amounted to less than 10% of the total iron content of the samples indicating that the iron minerals are either isolated from the main paths of flow through the samples or that the iron minerals present are only slowly soluble in HCl.

DISCUSSION

X-Ray Diffraction, HCl Solubility, and Iron Content Analysis

X-ray diffraction tests were performed on end pieces of the six submitted core plugs. Both the bulk mineralogy and the specific mineralogy of the clay fraction were determined for each of the samples tested.

In all cases, the majority of the sample was composed of quartz and a rather large amount of feldspar. Dolomite was present in fairly small quantities ranging from 1 to 9% in five of the six samples tested, as was anhydrite at 2 to 6%. The exception was Sample 35 which contained 22% dolomite and no anhydrite. Sample 35 was also the only sample in which an iron bearing mineral was detected (3% hematite). Clay content of all samples was quite low overall with illite being the predominant clay mineral present, along with trace quantities of chlorite. The total clay fraction of each sample generally comprised 5% or less of the total mass of the sample. Neither illite nor chlorite is a water swelling clay (as smectite or mixed layer illite/smectite would be) although either could be susceptible to migration within the formation. XRD results from bulk mineralogy tests are shown in Table 1.

A separate x-ray diffraction run was also made on each sample to determine the composition of the fraction of each sample that was composed of particles less than 5 microns in diameter. This gives a more detailed view of the composition of the clay fraction of the sample. This analysis showed the majority of the clay sized fraction was composed of illite. Samples 48, 53, and 57 also contained a significant amount of colloidal sized quartz particles (20% of the <5 micron fraction). XRD results from the <5 micron particle size fractions are shown in Table 2.

The composition of the <5 micron particle size fraction of Sample 35 was sufficiently different from the other five samples tested to warrant separate discussion. The clay size fraction of this sample contained a considerable amount of hematite (22%) and dolomite (13%) along with illite, chlorite and quartz whereas the clay sized fraction of the other five samples were composed almost exclusively of illite, chlorite, and quartz. The primary visual difference between Sample 35 and the other submitted core plugs was the volume of shaly material that could be observed in the sample. While all samples contained thin shale laminations, Sample 35 appeared to contain at least 50% by volume of a reddish-brown shale, which was much more than the other samples appeared to contain. This would account for the variations in both the bulk and clay size fraction mineralogy of this sample from the others. The composition of this sample would also seem to indicate that the reddish-brown shale is the primary source of dolomite and hematite in the samples. As the permeability of the shale would be expected to be much lower than that of the sandstone portions of the interval, fluid contact with either the dolomite or hematite in the samples would probably be very limited. This hypothesis is supported by the acid core flow test results that will be discussed later in this report.

No iron bearing minerals were detected by x-ray diffraction within any of the samples except for Sample 35. It is likely that iron oxides are present in these samples, but not in large enough quantities to be detected by XRD.

DISCUSSION (Cont'd)

X-Ray Diffraction, HCl Solubility, and Iron Content Analysis (Cont'd)

Gravimetric HCl solubilities for the samples ranged from 8.84% to 16.96% in all samples except Sample 35, which had an HCl solubility of 34.04% due to its high dolomite content. These values may seem high, as they significantly exceed the mass percentage of carbonate minerals present. The additional mass lost after exposure to HCl in addition to the carbonate minerals is likely coming from aluminum being leached from the large amount of feldspar present, anhydrite which is partially soluble in HCl, and dissolution of the trace quantities of halite present. As these solubility determinations were made on finely ground samples, there is significantly more surface area available for acid contact than there would be in an unground sample; therefore, the solubility reported here is most likely higher than what would actually be realized during acidization.

The acid soluble iron content of the samples ranged from 0.53% to 1.64%, indicating that there is some source of iron present, even if it is not always detectable by x-ray diffraction. While not exceedingly high, iron levels in excess of 1.0% are generally regarded as being a potential concern when acidizing. It can be noted that Samples 19 and 20, which were gray in color, both contained significantly less iron than Samples 35, 48, 53, and 57 which were all reddish-brown.

SEM examination of three of the core samples showed the samples to be composed of 30-50 micron grains of quartz and feldspar. Porosity was characterized as good to very good, with little infill of pore spaces by clays or other minerals. Photomicrographs of the three core samples tested are shown as Figures 1 through 3.

Non-Acid Core Flow Tests

The results of the three flow tests conducted to determine the effect on formation permeability after exposure to a test fluid are included both in graphical and tabular form in the data section of this report. The test fluids to which the formation samples were exposed were de-ionized water, a 0.2% Clayfix II solution, and a 2% KCl solution. These tests were carried out to determine detrimental effects to formation permeability that may occur when the formation face along a hydraulic fracture is subjected to leak-off of the base fluid from a fracturing treatment.

Briefly, the procedure used to perform these tests was:

1. Mount a formation core in a Hassler sleeve assembly heated to 88°F and flow filtered formation brine through the core until a stabilized differential pressure across the core was observed. From this value, the baseline permeability of the sample prior to exposure to the test fluid was determined based on the core samples dimensions, the liquid flowrate, and the viscosity of the formation brine (which was determined to be 1.70 cP at 88°F).

2. Thirty ml of the test fluid was flowed in the reverse direction from which the formation brine was injected. This constituted six to eight pore volumes of displacement for the plugs used. This step simulates the leakoff of the fracturing base fluid into the fracture face.

DISCUSSION (Cont'd)

Non-Acid Core Flow Tests (Cont'd)

3. Filtered formation brine was once again injected to the core plug in the forward direction until a constant pressure value was observed. The initial and final permeabilities to the formation brine were then compared to each other to judge the effect of the test fluid exposure on the sample permeability.

Three figures containing two graphs each are included to show the effects of test fluid exposure for each of the three tests conducted. The upper graph shows the permeability of the sample as a function of total injection volume while the lower graph shows the same results expressed as a ratio of the permeability of the sample after exposure to the test fluid to the initial stabilized permeability (k/k_i). These are shown as Figures 4, 5, and 6 in the data section of this report. Tabular values of the results are found in Table 3. As the tests were conducted on separate core samples with varying initial permeabilities, some degree of variability in the results would be expected from sample to sample with the same test fluids; however, there does appear to be a clear trend in the permeability variations caused by exposure to the test fluids.

Test 1 was conducted on Sample 48 using de-ionized water as the test fluid. Substantial permeability reduction was noted (-23.3%) after exposure to the fresh water as the permeability fell from an initial value of 8.31 md to a final value of 6.37 md. Although this loss may seem high, it does not approach the 100 to 1000 fold permeability reductions that are observed in extremely fresh water sensitive formations after only one or two pore volumes exposure to fresh water.

Test 2 was conducted on Sample 20 using 0.2% Clayfix II in de-ionized water. Clayfix II is used as an alternative to a KCl base fluid in fracturing treatments. A small amount of permeability loss was observed after exposure to this test fluid as the initial value of 18.6 md fell to a final value of 16.9 md for a total loss of 8.9%. The permeability loss was significantly mitigated from that observed when using DI water however.

Test 3 was conducted on Sample 35 using 2% KCl as the base fluid. In this test a 9.6% permeability gain was observed as the permeability increased from an initial value of 0.73 md to a final value of 0.80 md. Note that the initial permeability of this rock was an order of magnitude lower than the other two samples tested. In any case, the use of 2% KCl appeared to completely prevent permeability loss from occurring.

One factor that will help mitigate permeability loss in this formation due to fresh water exposure is the high salinity of the formation brine. The specific gravity of the brine (1.195) and the chloride content (194000 mpl) indicate the brine is essentially saturated with sodium chloride. Thus a large amount of dilution of the connate water with treating fluid would have to occur before permeability reduction occurs in this formation.

Overall, based on the results of this testing, this formation should be considered slightly sensitive to extremely low salinity water. However, a 23.3% loss in permeability along the fracture face would probably not significantly effect the success

DISCUSSION (Cont'd)

Non-Acid Core Flow Tests (Cont'd)

of a fracturing treatment. Due to the large surface area exposed once a fracture is propagated, high levels of damage to the formation face are tolerable without any significant loss in production as compared to an identical treatment accomplished with no damage to the formation near the fracture face. For this reason, the use of fresh water as a base fluid for a fracturing treatment of this well could be considered as an option. The formation should not be considered completely immune from negative effects caused by fresh water exposure however. For example, fresh water should not be used as a completion or workover fluid where near wellbore exposure to the fluid would occur. In this case, the flow geometry is quite different from the flow geometry of a fractured well and a 25% loss of near wellbore permeability could have a significant impact on well performance.

These tests are only indicative of the sensitivity of the formation to fresh water and do not address other effects that exposure to an aqueous fluid might have on the production capacity of the fractured well when two phase flow is in effect, such as water blocks or slow load recovery following a fracturing treatment.

Acid Core Flow Tests

Two core flow tests using 7.5% Fe Acid and 15% Fe Acid were conducted to determine the effect of acidization on the submitted core samples both in terms of permeability response and in iron release in the acid effluent. Both tests were run in exactly the same manner. The procedure was similar to that used in the non-acid core flow tests, except that all fluid injection was carried out in the same direction through the core, and the acid volume injected was 100 ml (approximately 20 pore volumes).

The results of these two tests are shown in Figure 7 as permeability vs. total injection volume. Tests 4 and 5 were conducted on Sample Nos. 53 and 54 from depths of 2192.65 ft and 2194.0 ft. The two plugs were very similar in terms of appearance, mineralogy, and permeability and porosity; therefore, the test results with the two acid systems should be directly comparable to each other without sample heterogeneity being much of a factor.

It can be seen that the results of the two different strengths of acid on the two cores are essentially identical in terms of induced permeability changes. Both cores start with an equilibrium permeability value to formation brine of about 8.5 md. As the fluid is changed to Fe Acid, the change from one fluid reservoir to another causes a brief pressure disturbance. This disturbance results in the calculated permeability spiking sharply upwards for a short period of time and then returning to the stabilized value. This period of injection is marked as "re-equilibration" on the two graphs and represents the transit time from the change of fluids to the point when acid actually reaches the core face. The permeability increase shown during this time is an artifact of the test not due to any reaction between the acid and the core sample.

As acid reaches the core sample, a sharp decrease in permeability is noted. Part of this apparent decrease is an artifact of the test and part is an actual reduction in permeability. As acid enters the core, it will displace the formation brine present in the

DISCUSSION (Cont'd)

Acid Core Flow Tests (Cont'd)

plug. However, since the viscosity of the acid is significantly lower than that of the formation brine, the transition within the core between the two fluids will be gradual. In calculating the sample permeability however, the viscosity change is assumed to take place instantaneously. This assumption causes the apparent permeability of the core plug to drop suddenly at the point where the viscosity change was entered. A second factor contributing to the decrease in permeability is that the reaction of the acid with the small quantity of carbonate minerals in the samples will result in the release of CO_2 gas until all carbonates have been dissolved by the acid. Thus for a brief period of time, both gas and liquid are flowing in the core, causing a reduction in relative liquid permeability until the gas is displaced. At actual reservoir pressure, this gas will largely remain in solution however.

Shortly after the acid reaches the core plug, it can be seen in both tests that the permeability ceases its decline and begins a gradual increase until the fluid is once again changed to formation brine. At this point the combination of a pressure fluctuation caused by changing fluid reservoirs and the change in viscosity of the fluids causes the permeability to spike upward once again. As the flow of formation brine continues, the permeability stabilizes. Comparison of the initial permeability to formation brine prior to exposure to acid and the final stabilized permeability to formation brine after acid exposure, yields the net effect of the acidization of the core. This information is found in Table 3 which shows that the net increase in permeability realized after acidization in Tests 4 and 5 was 30.8% and 23.0%, respectively. This is a rather negligible increase in permeability, but it is not surprising since, as was previously discussed, most of the carbonate material in this sandstone appears to be localized to the reddish-brown shale laminations in this formation. These portions of the interval would be expected to have much lower permeability than the cleaner sandstone portions; hence, acid contact with carbonate minerals would be expected to be limited.

The second point of interest in the acid flow tests was the ionic content of the acid effluent from the cores during acidization, particularly in the iron content in the acid exiting the core. This topic was addressed by taking seven acid effluent samples over the course of the 100 ml of acid injection to each core during tests 4 and 5. These samples were analyzed to determine the levels of dissolved iron, calcium and magnesium. The results of these analyses are shown in Table 4.

The levels of dissolved iron in both tests were quite low. In Test 4, the iron levels varied from 459 mpl at the beginning of acid flow to 252 mpl after 100 ml of injection of 7.5% Fe Acid. In Test 5, which used 15% Fe Acid, the iron levels were only slightly higher, varying from 613 mpl to 342 mpl. As regular strength Fe Acid will chelate in excess of 5000 mpl of Fe^{+3} at the BHT of 88°F, there appears to be no basis for concern over iron precipitation problems occurring due to liberation of iron from the formation into the acid used to treat the formation.

It should also be noted that only a small percentage of the total acid soluble iron in the formation was removed from the samples by the 100 ml (20 PV) of acid that was injected during the core flow tests. For example, based on the total mass of

DISCUSSION (Cont'd)

Acid Core Flow Tests (Cont'd)

Sample 53 and the calculated total iron content of 1.24% (by mass), as reported in Table 1, the total mass of acid soluble iron in Sample 53 is 0.50 grams. Integration of the Fe concentration vs. acid volume curve obtained from the flow test on this sample shows that the total mass of iron dissolved by the injected acid was approximately 0.03 grams, or only 6% of the total iron present. As it appears that a large portion of the iron present in this formation is localized to the reddish-brown shale laminations in the formation (probably in the form of hematite) that will have little contact with the injected acid, the fact that only a small percentage of the total iron in the formation is dissolved by the injected acid is not surprising.

The levels of calcium and magnesium in the acid effluent samples indicate that some dolomite is being dissolved by the acid. The levels of these ions detected in the effluent samples from Tests 4 and 5 indicate that except for the first 20 ml of acid injected, there is no significant difference between 15% Fe Acid and 7.5% Fe Acid in regard to the volume of dolomite being dissolved or the rate at which dissolution occurs.

DATA

Qualitative X-ray Diffraction, Iron Content, and Acid Solubility Analyses

Purpose: To identify the types and relative quantities of minerals in the formation sample.

Procedure: A pulverized one gram sample is placed in an x-ray beam and rotated through an arc. The x-ray beam is diffracted by the sample and the diffraction patterns are recorded.

Results: The diffraction patterns are used to identify the types of minerals present and their relative quantities. The relative quantities for the submitted samples are as follows:

DATA (Cont'd)

Table 1

Sample No.	19	20	35	48	53	57
Depth (feet)	2181.35	2181.7	2186.65	2191.00	2192.65	2194.00
HCl Solubility%*	10.32	16.96	34.04	11.2	8.84	11.28
Iron Content%**	0.54	0.53	1.43	1.64	1.24	0.89
Quartz %	63	55	46	64	56	64
K Feldspar %	6	5	2	7	9	7
Na Feldspar %	22	21	15	20	22	18
Calcite %	0	trace	trace	0	0	trace
Dolomite %	1	9	26	2	4	2
Anhydrite %	5	6	-	2	3	4
Gypsum %	0	trace	-	0	0	0
Pyrite %	0	0	-	0	0	0
Illite %	3	4	4	4	6	2
Chlorite %	1	trace	2	trace	1	trace
Hematite %	-	-	3	-	-	-
Halite %	trace	trace	2	trace	trace	trace

* This is solubility by actual weight loss after reaction with an excess amount of 15% HCl at 150°F for 60 minutes.

** One gram of sample is added to the HCl from the gravimetric solubility test. The dissolved iron is titrated with Potassium Dichromate and reported as percent by weight.

DATA (Cont'd)

Qualitative X-ray Diffraction (Cont'd)
<5 micron Clay Size Fraction*

Table 2

Sample No.	19	20	35	48	53	57
Depth (feet)	2181.35	2181.7	2186.65	2191.00	2192.65	2194.00
Quartz %	4	trace	10	20	18	20
K-feldspar %	0	0	4	0	0	0
Na Feldspar %	0	0	trace	0	0	0
Illite %	90	88	40	56	64	75
Chlorite %	6	7	11	7	7	5
Hematite %	0	0	22	0	0	0
Dolomite %	0	5	13	0	0	0

* A ground formation sample is dispersed in distilled water and the liquid is decanted and placed in a centrifuge at 2000 rpm for 2 minutes. The supernatant fluid is then dried, and an x-ray diffraction analysis is performed on the remaining colloidal solids.

DATA (Cont'd)

Core Flow Test Results
Permeability Loss or Gain Due to Test Fluid Exposure

Table 3

Test No.	Sample No.	Test Fluid	Initial Stabilized Perm. (md)	Final Stabilized Perm. (md)	% Permeability Loss/Gain
1	48	Fresh* Water	8.31	6.37	-23.3
2	20	0.2% Clayfix II*	18.59	16.93	-8.9
3	35	2% KCl*	0.73	0.80	+9.6
4	53	7.5% Fe Acid	8.24	10.78	+30.8
5	57	15% Fe Acid	8.92	10.97	+23.0

* Thirty ml of the test fluid (6 to 8 pore volumes) were injected in the reverse direction from that used to determine the initial and final stabilized permeabilities to formation brine.

DATA (Cont'd)

Core Flow Test Results (Cont'd)
Ionic Content of Acid Effluent

Table 4

	Volume HCl (ml)	Fe (mpl)	Mg (mpl)	Ca (mpl)
	0-10	459	2196	6415
	15-20	467	1673	6671
	30-35	411	1099	5785
Test 4 (7.5% Fe Acid)*	45-50	337	647	5264
	60-65	298	467	4756
	70-75	270	384	4350
	95-100	252	257	2671
	0-10	613	3297	9055
	15-20	627	2493	8331
	30-35	470	1110	5743
Test 5 (15% Fe Acid)*	45-50	407	703	5139
	60-65	358	482	4694
	70-75	361	406	4552
	95-100	342	295	4331

* Formation brine was injected into the cores until a steady permeability response was observed. One hundred milliliters of acid were then injected, from which the samples listed were collected at the core outlet for ionic content analysis. Injection was then returned to formation brine until a steady permeability response was again observed.

DATA (Cont'd)

Scanning Electron Microscope (SEM) Examination

Purpose: To provide a greatly magnified view of a core sample. Minerals present in the sample can be identified and their location observed.

Procedure: A core chip with a freshly broken surface is required for this examination. The sample is coated with a gold palladium alloy and placed in the vacuum chamber of the SEM. The core chip is viewed at a high magnification and a photomicrograph is taken. An associated energy dispersive x-ray (EDX) is used to help identify the mineral content of the sample.

Results: The framework grains can be identified and their size approximated. The location of the clay minerals within the sample can be observed. The SEM can produce, in effect, a pseudo three-dimensional view of formation pore spaces. The area of the sample viewed is very small and may not clearly characterize the entire formation.

DATA (Cont'd)

Scanning Electron Microscope (SEM) Examination

Sample No: 20
Depth: 2181.7 ft.

Figure No. 1; Negative No. 7535; Magnification 100X/500X.

This sample has a loosely consolidated framework composed of irregular, 30-50 micron sized quartz, feldspar and dolomite grains. A lot of the original porosity remains; the porosity is estimated to be good to very good. Some secondary quartz growth is evident in the sample. Plagioclase and potassium feldspar are both present in authigenic and detrital forms. Some grains are partially dissolved away. A small amount of anhydrite was also observed. The photomicrograph shows the close association of the various minerals present in the sample.

DATA (Cont'd)

Scanning Electron Microscope (SEM) Examination (Cont'd)

Sample No: 48
Depth: 2191.00 ft

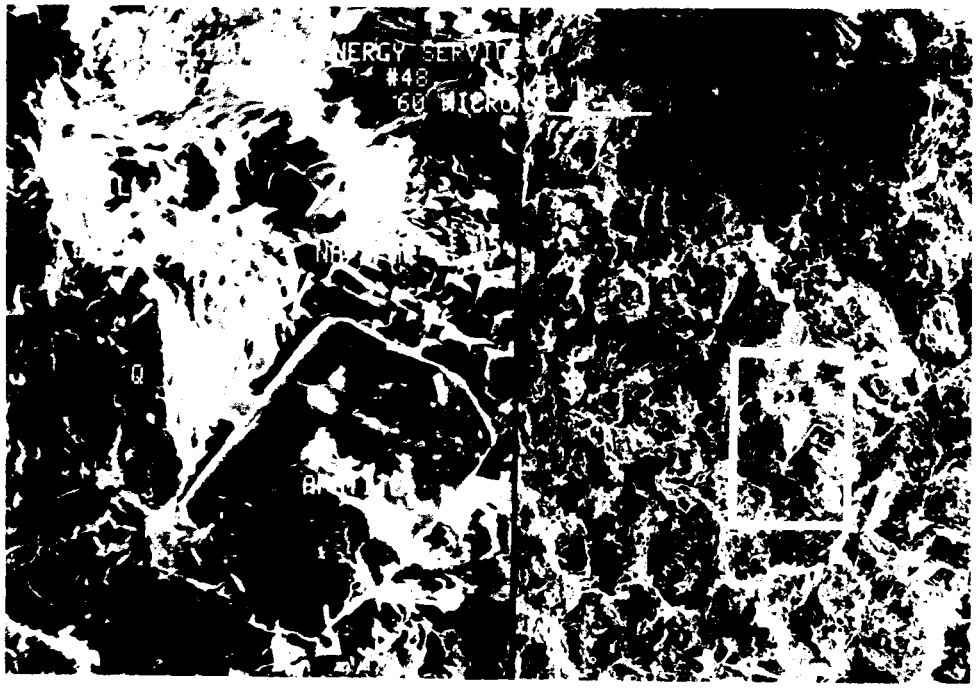


Figure No. 2; Negative No. 7536; Magnification 200X/1000X.

This sample is similar to Sample #20, with a framework of 30-50 micron sized, irregularly shaped grains of quartz and feldspars. Porosity remains good, but more illite clay seems to be present. The photomicrograph shows the framework structure and includes a grain of apatite which is present in the core in trace amounts. The sample exhibits secondary quartz overgrowth and contains authigenic and detrital feldspars.

DATA (Cont'd)

Scanning Electron Microscope (SEM) Examination (Cont'd)

Sample No: 53
Depth: 2192.65 ft.

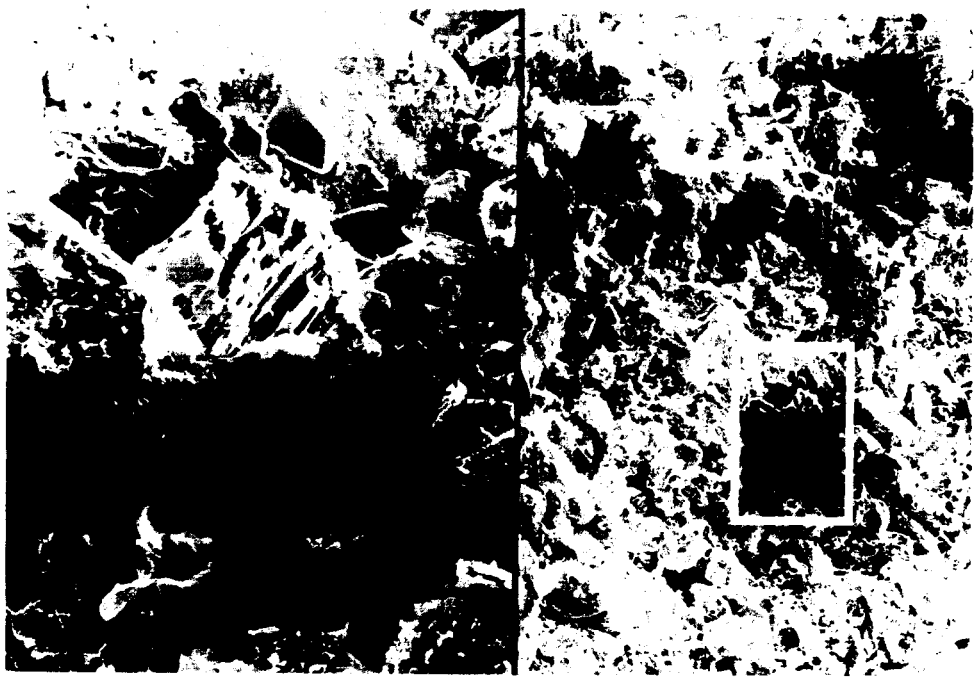


Figure No. 3; Negative No. 7537; Magnification 100X/500X.

The photomicrograph shows the irregular grains of quartz and feldspar which make up the framework structure of this sample. The framework grains are lightly coated with illite clay. Anhydrite is present in some areas as an infill and coating material over some grains. Very little dolomite seems to be present in this sample. Porosity remains good.

Figure 6

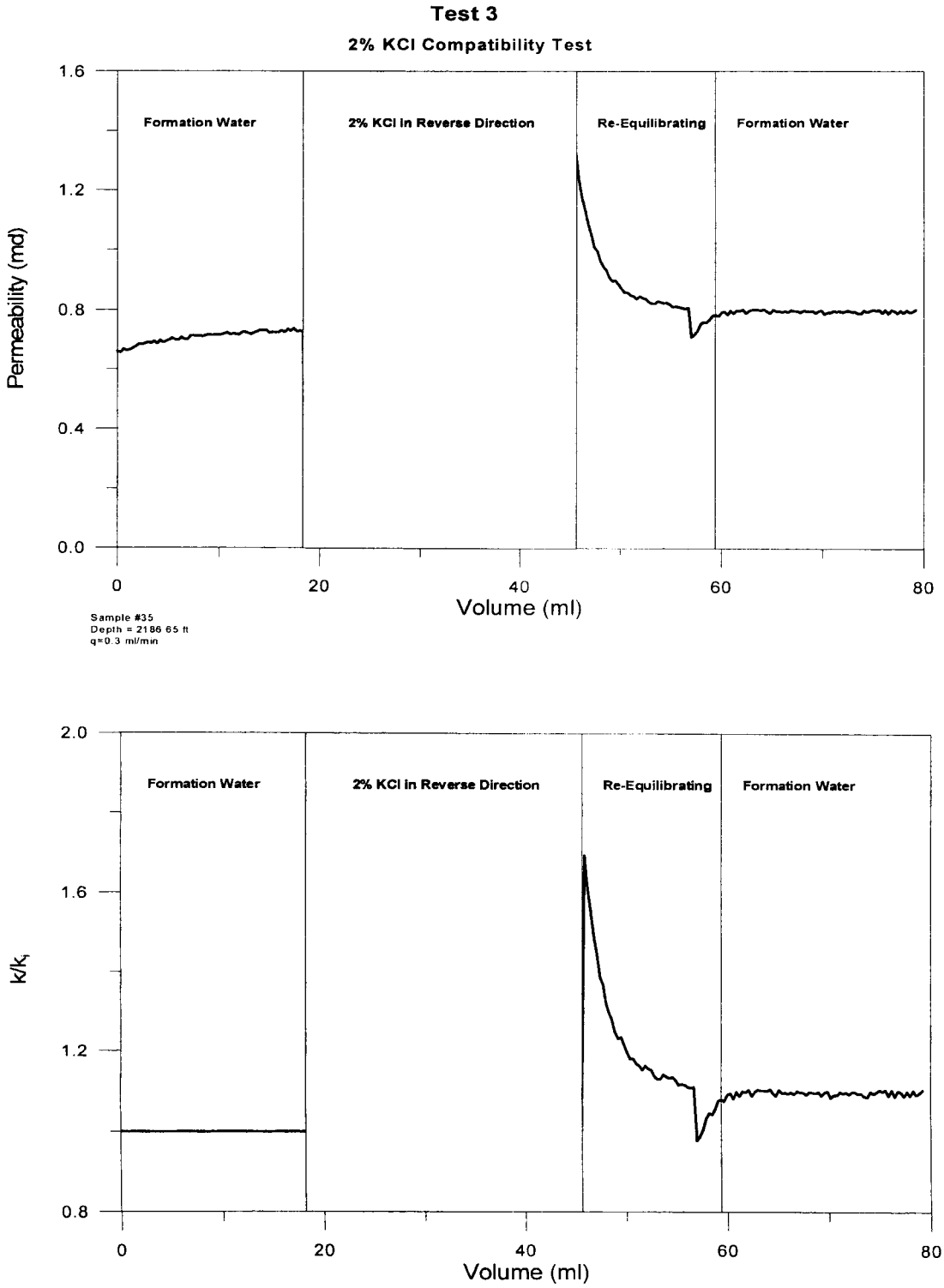
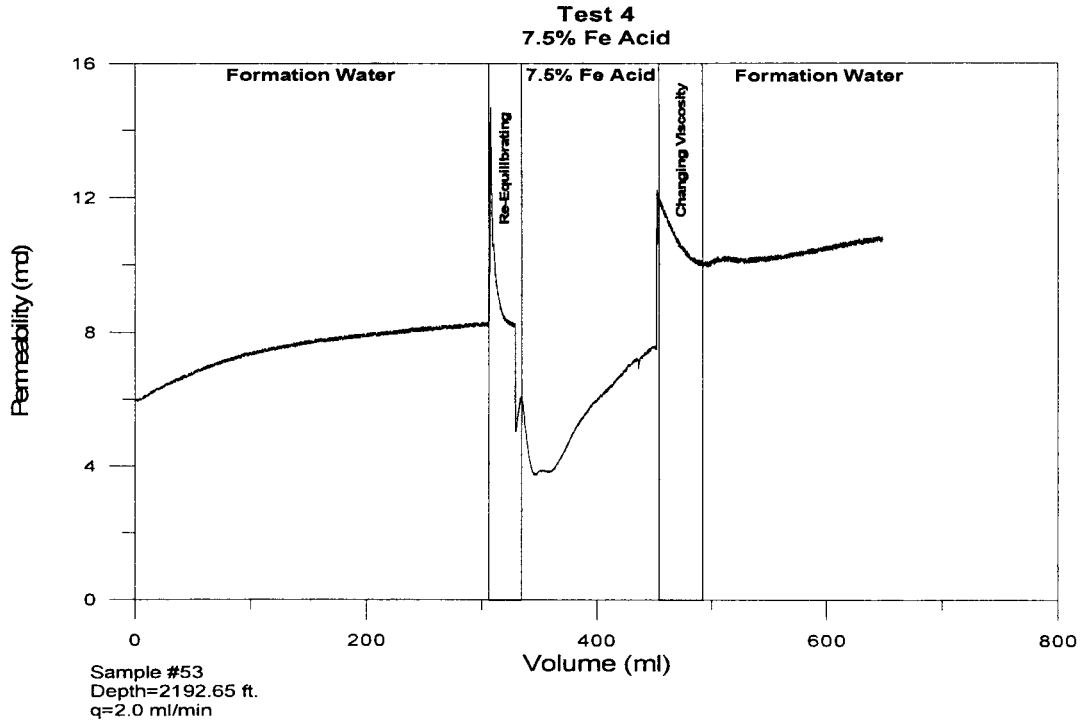


Figure 7



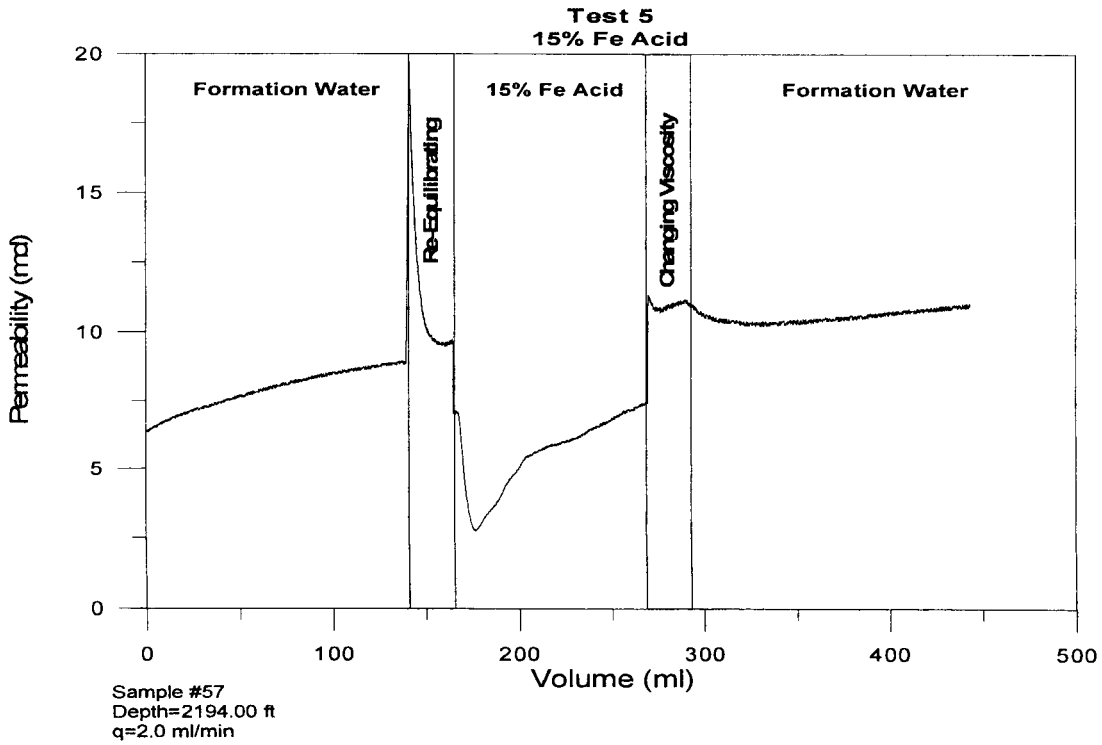


Figure 4

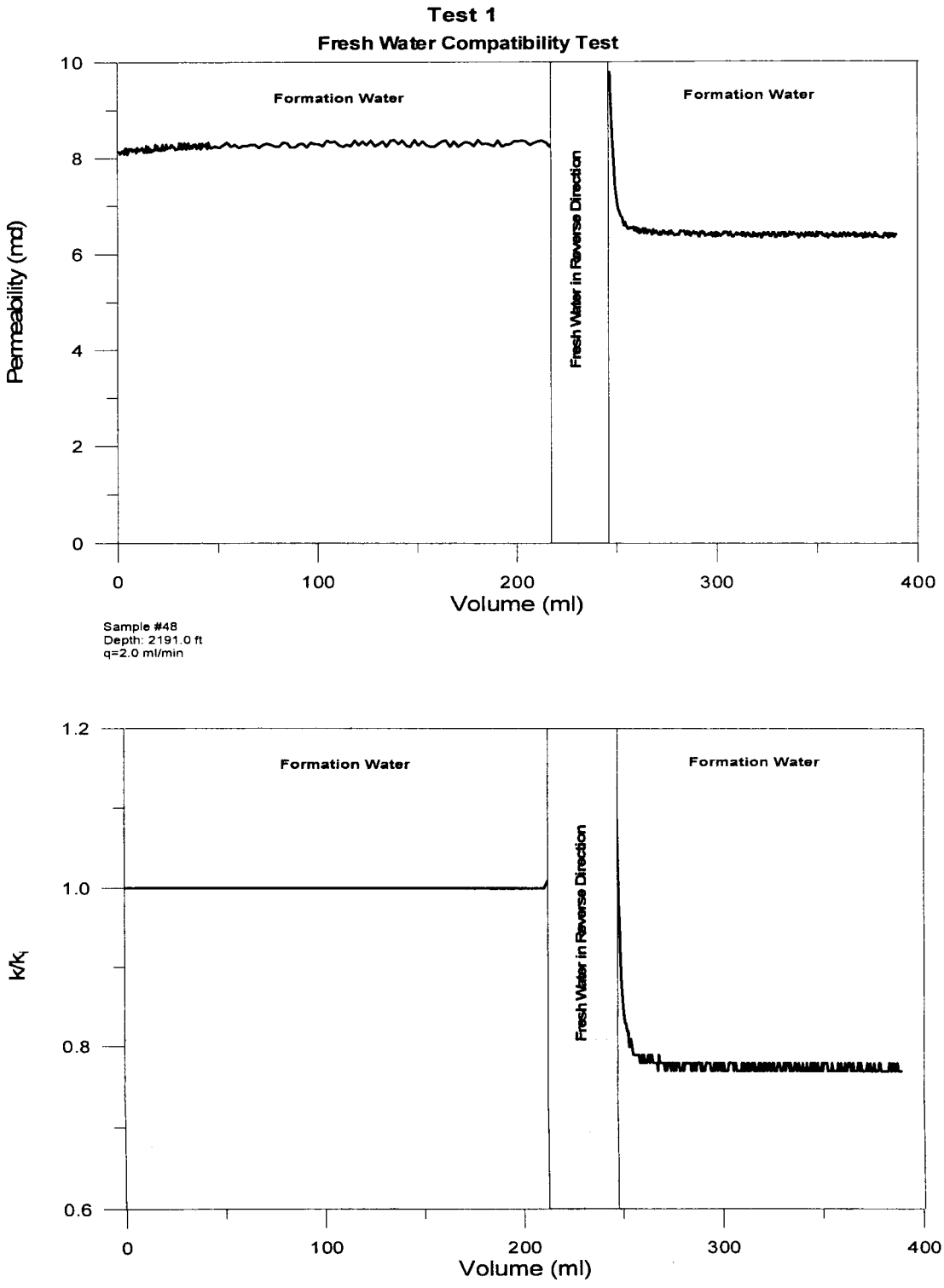


Figure 5

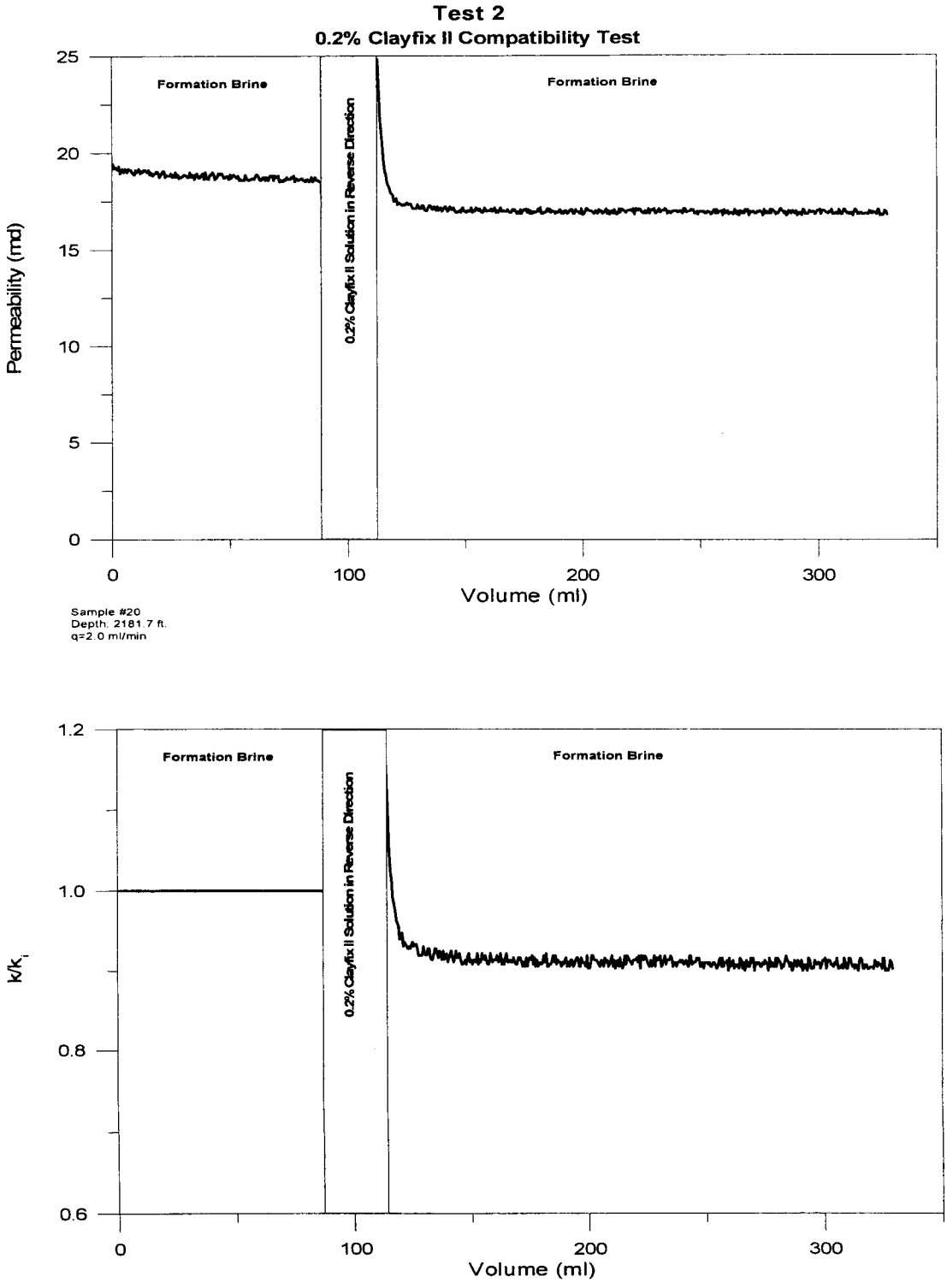
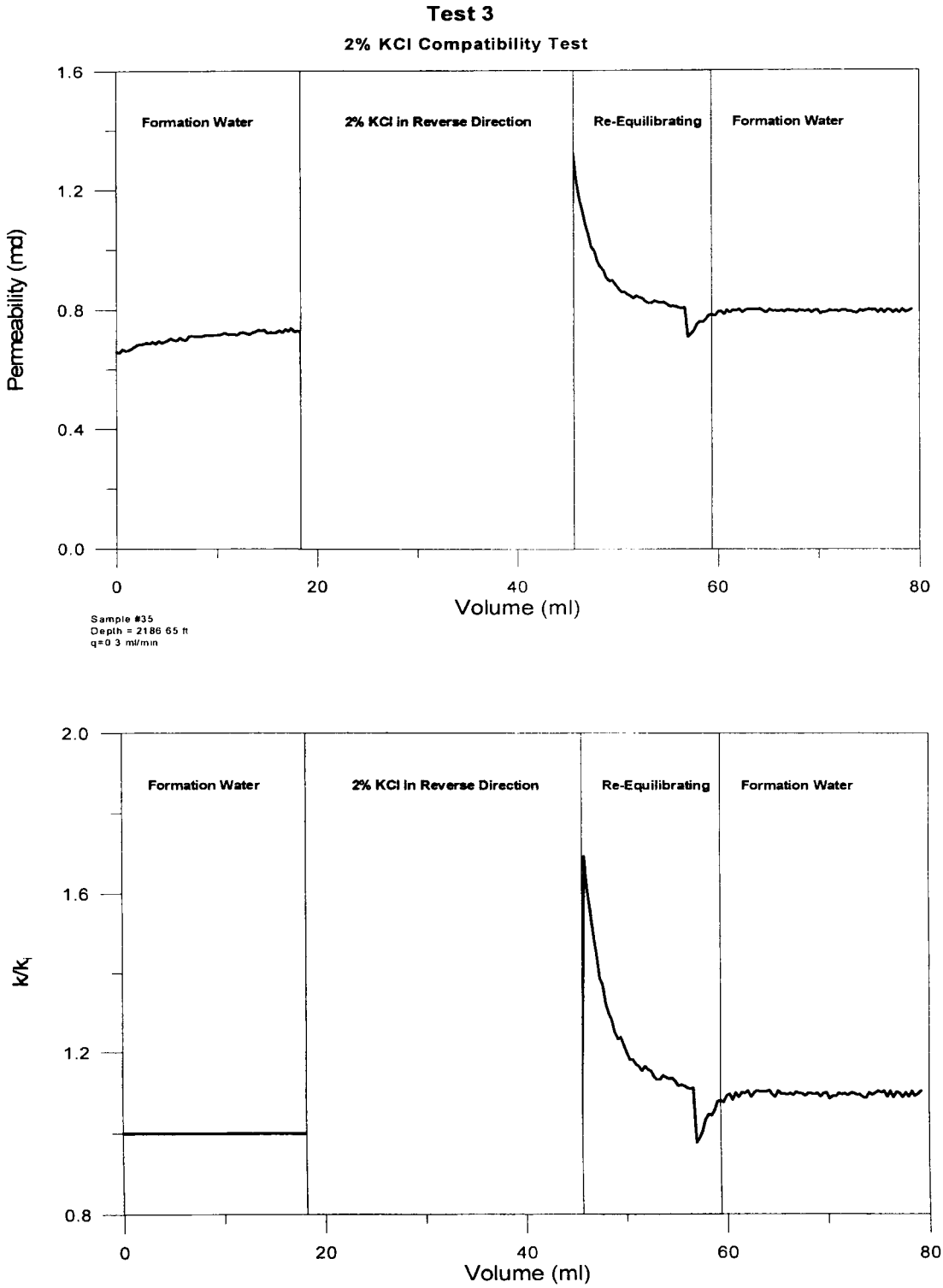


Figure 6



REMARKS

The data in this report were given to Mr. Shane Fross by Mr. Rick Behenna by fax on December 9, 1994.

CORE SAMPLE DISPOSITION

The core samples will be held in storage for 60 days following mailing of the report. At the end of this time, we will select representative core pieces for storage in the Core Library and discard the remainder unless we are requested to ship the cores to another location.

DATA BOOK REFERENCE

The data presented in this report are recorded in:

Department	Book No.	Page No.(s)
Analytical	7694	73
Analytical	7678	63
Analytical	7705	5
Analytical	7683	69
Stimulation Engineering	7689	17-21

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Mr. W. K. Ostroot
Mr. H. C. Tan
Stimulation PSL - Duncan

Respectfully submitted,

Laboratory Analyst

Blanton-Clark-Halterman-Loghry
sy

HALLIBURTON ENERGY SERVICES

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