USE OF WET GAS TO MODEL LONG-TERM FRACTURE CONDUCTIVITY

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ABSTRACT

Significant advances have recently been made in laboratory attempts to measure realistic fracture conductivity values for proppants at reservoir conditions. This paper will give a brief overview of recent work throughout the industry related to conductivity testing, and efforts being made to simulate the environment of fracturing proppants during a well's producing life. Also presented will be data showing that test results can be significantly different when using wet gas as the flowing medium following a short period of flowing brine water. Listed below are the nine most important test parameters that need to be incorporated into the test procedure:

Reservoir Temperature
Extended test times
Core wafers
Gel residue within the proppant pack
Gel filter cakes from dynamic fluid loss tests
Shear preconditioning of fluids in fluid loss tests
Frac fluid clean-up
Wet nitrogen gas as flowing medium (to model gas wells)
Multiple closure stress values

Previous authors have modeled some of these variables, but this paper will present data where all parameters listed above are included. These test results will allow an operator to more accurately model a fracturing treatment with a design simulator and thus predict the post-frac production using a reservoir simulator.

INTRODUCTION

The primary purpose of most hydraulic fracturing treatments is to create a highly conductive fracture that extends for a significant length into the reservoir rock. For the treatment to be successful the proppant filled fracture must maintain high conductivity.

Fracturing treatment design simulators use laboratory generated conductivity (or permeability) data to estimate the fracture conductivity of a treatment that is being planned. The resulting model of the propped fracture is used to estimate the production increase expected from the stimulation treatment. For these predictions to have much validity it is necessary to use realistic estimates of the conductivity of the propped fracture.

For many years, the conductivity data were mostly generated on clean proppant samples with closure stress applied to the proppant for only a short time.[1-4] Since most testing of this type was performed at low temperatures with gas or filtered

liquids, the effect of extended testing times was only important for very high stress levels. Generally, the net result of this tranquil testing environment resulted in an overestimated fracture conductivity for the proppant pack being tested. Figure 1 illustrates the difference in conductivity data when short tests times are used versus data from long term tests.

To provide a graphic example of the effect that this overestimation will have on fracturing treatment design, a frac design simulator was used. The well conditions given in Table 1 will be used as an example case. This is a gas well with 0.5 md permeability and it is desired to achieve a steady state production increase (P.I.) prediction of five-fold with a fracturing treatment.[1,5] The fluid and treating conditions chosen for the simulation are given in Table 2. Multiple simulator runs were needed to determine the necessary pumping schedules to obtain designs with a propped length between 800 and 1000 ft and a P.I. of five-fold. The design simulator program was first run using conductivity data measured at short time test conditions, as represented by the top curve in Fig. 1, to determine the necessary treating schedule to achieve a five-fold production increase. The simulator was then run using long term conductivity data at 200°F, as in the third curve on Fig. 1. Tables 3 and 4 list the two pumping schedules that were required based on the respective set of conductivity data used by the simulator. The short time data predicted only 80,000 lb (800 sacks) placed at 1, 2 and 3 lb/gal would suffice. The simulation using the long time data at reservoir temperature specified that much more proppant would be required (1,500 sacks) and at concentrations up to 5 lb/gal. At higher closure stress and/or higher temperatures the additional proppant and necessary proppant concentrations would show even more contrast than illustrated by this example.

In the late 1970's and early 1980's, reservoir engineering technology had given the petroleum engineer new methods of transient pressure analysis that allowed him to calculate postfrac estimates of fracture conductivity.[6,7] However, in a large number of cases the calculated conductivities were significantly different than had been predicted by the design simulator. Some published examples reported discrepancies of 10-fold or more.[8,9] These results created a renewed interest in trying to better simulate realistic reservoir conditions in the laboratory measurement of proppant bed conductivity.

Although Cooke[10] had published data indicating some of the effects of brine at high temperatures many years earlier, the industry as a whole continued to generate most conductivity data under tranquil, low temperature and short time test conditions. Some investigators attempted to show the effects of gelled fluids on the fracture conductivity. Almond and Bland[11] reported conductivity reductions of 20 to 60%, but their tests did not incorporate any stress on the proppant. Later, Kim published work[12] that attempted to incorporate stress and gel residue in a linear cell, but these data were for very short test times at stress, and did not include any gelled fluid filter cakes in the tests.

Investigators of the early 1980's, who attempted to use long test times at high temperatures, experienced several procedural problems, mostly related to corrosion of the test apparatus or the cell itself.[13] McDaniel[14] brought to industry attention the importance of oxygen removal from the test system to help overcome many of these corrosion problems. The need for presaturating the test fluid with silica with

respect to the effects on some proppants was also shown in that work. Later, Brown and Much[15] discussed this effect in great detail. In May of 1986, McDaniel presented a more complete set of data that quantified the effects of long test times at simulated conditions of stress and temperature.[16]

The next step was to include the use of core as the material contacting the proppants, and to also build a fluid loss filter cake on this core surface before introducing proppant into the gap between the core faces. Roodhart, et al.[17] published the first meaningful work that attempted to model the effect of fluid loss filter cake. Test conditions in that work may be too severe, since the procedure switched directly to gas flow following the fluid loss test with no liquid flow time at all. Some concern has been expressed about the validity of the geometry of the proppant pack inside this cell, since the fluid flowed across the core face from two points along the circumference of the circular face 180°F apart. Figure 2 is a simple schematic that illustrates the possible flow paths.

In the spring of 1987, Much and Penny[18] offered data from tests wherein they used a linear test cell with modified pistons to allow the use of formation core wafers as the fracture face. The cells would also allow a dynamic fluid loss test to be conducted in the assembled cell prior to injecting a slurry of the proppant to be tested. In the fall of 1987, Penny[19] published additional work using this apparatus. Concurrently, Parker and McDaniel[20] presented data which included gel filter cakes present on core faces in their conductivity tests. Two different cells were used in their study. One was a radial cell with flow from the center outward during the conductivity tests. The other cell was constructed to use the same core wafer geometry as the linear cell used by Much and Penny. This paper also illustrated the effect on treatment design that results from using conductivity data generated under realistic reservoir conditions.

Work presented here will show there is one more step to be considered. This procedural change is the use of a flowing medium that more closely models the fluid that will be flowing through the proppant bed for the majority of the producing life of the well. Nitrogen gas, presaturated with water, was used in an attempt to better model gas well behavior. Maloney, et al.[21] attempted to study the effects of flowing gas with a saturating phase present. However, the absence of gelled fluid filter cakes in the proppant pack prevent this work from being relevant to treatments using a gelled fluid. Roodhart, et al.[17] had used a pre-wetted gas, but as mentioned earlier the cell design may not give truly linear flow.

As illustrated by the work in this paper it was found that when wet gas was used following water based gelled fluids or water/oil emulsions that the results can vary significantly from tests using only brine water as the flowing medium. Future testing may need to incorporate liquid hydrocarbons as the flowing medium. Currently, the author is not aware of any published work using a liquid hydrocarbon as the flowing medium in conductivity tests conducted at realistic in situ reservoir conditions.

EXPERIMENTAL PROCEDURES

The general procedures used, as discussed briefly below, are similar to those used by Much and Penny,[18] Penny,[19] and Parker and McDaniel,[20] with the exception of the tests which switched to wet gas as the flowing medium after at least one day of brine water flow. The test cell used is the same as the linear cell described by Parker and McDaniel in Phase III of their work. For this reason it will only be briefly described here. Figure 3 shows a simplified drawing of the cores and proppant pack inside this test cell.

Fluid Loss Test Procedure

The fluids used for fluid loss tests were batch mixed, with only the crosslinker (if used) added during the pumping operation. At the 60 minute mark of the fluid loss test, 20/40 Ottawa sand was introduced. This was accomplished by using a separate volume of the gelled fluid to which enough sand was added to make a 1 lb/gal slurry. After 10 minutes of pumping this mixture, a measured amount of sand was added to increase the concentration of the remaining slurry to 3 lb/gal for the next 10 minute pumping period. Again a measured amount of sand was added to the slurry to result in a slurry containing 5 lb/gal for the last 10 minutes of the fluid loss test.

The fluid was pumped at a rate of 1.3 liter per minute through a length of 0.25 in. stainless steel tubing to simulate the equivalent shear of 15 bbl/min in 2-7/8 in. tubing (2.44 in. ID). It then traveled for another 4 minutes through coiled 0.75 in. stainless steel tubing immersed in a heating bath to raise the fluid to the desired test temperature prior to entering the conductivity/fluid loss cell. This larger tubing was sized to result in a shear rate similar to the shear rate in the cell when using a 0.25 to 0.30 in. gap width. At a flow rate of 1.3 l/min the shear rate is approximately 40 sec^{-1}. Figure 4 presents a diagram of the fluid flow path used in the test procedure.

The pumping schedule followed is presented below.

Stage 1: Pump 2% KCl water for 10 minutes. Measure permeability of core wafers during this time.
Stage 2: Pump gelled fluid for 60 minutes.
Stage 3: Pump gelled fluid with 1 lb/gal sand for 10 minutes.
Stage 4: Pump gelled fluid with 3 lb/gal sand for 10 minutes.
Stage 5: Pump gelled fluid with 5 lb/gal sand for 10 minutes.
Stage 6: Terminate fluid loss test and inject desired proppant.

Conductivity Test Procedure

Following injection of the proppant to be tested, a closure stress of 1,000 psi was applied and excess fluid in the cell allowed to bleed off. After this was completed, the cell was repressured to 200 psi with 2% KCl water (but not flowed) and shut in overnight, typically 14 to 18 hours. The initial width of the proppant pack was determined by caliper measurement of the piston lengths protruding from the cell body. The flow of 2% KCl water was started at 1 ml/min and all excess air bled from the lines and differential pressure transducer (ΔP cell). Conductivity measurements

were then made using four or more flow rates through the proppant pack. Flow rates were typically 10, 8, 6 and 4 ml/min, unless a lower set of flow rates was required because the differential pressure exceeded the range of the ΔP cell (20 in. H_2O).

The closure stress remained at 1,000 psi until it was relatively stable, usually 20 to 50 hours. At this time, the procedure varied depending on whether wet gas was used for the test, or if the test used only 2% KCl water. If the test used wet gas, flow was initiated at this time and the stress held at 1,000 psi until the conductivity stabilized. This required 50 to 100 hours. Following this step, stress was raised to the desired level and held until the conductivity again stabilized, sometimes requiring up to 150 hours. At the end of this period, the test was normally terminated. On one test only 2% KCl water was used at stress levels below 4,000 psi. After a stable conductivity was achieved the flowing medium was changed to wet gas, holding the stress at 4,000 psi until confident the conductivity was constant before raising the stress to 6,000 psi.

The wet gas used in this experimentation was nitrogen saturated with water. A heated presaturation chamber was designed to ensure the nitrogen was saturated prior to entering the conductivity cell. The values used for viscosity of the wet nitrogen gas were for pure nitrogen gas under the same pressure and temperature conditions. A literature search did not result in finding a suitable data base for wet nitrogen viscosity data at test conditions. The literature that was found indicated the error in viscosity should be very small at the test temperatures and pressures used. Gas flow rates of 0.2 to 5 standard liters per minute (SLPM) were used.

The proppant pack was visually inspected after cell disassembly to compare the condition of the filter cake to the tests with and without wet gas as the flowing medium.

FLUID SYSTEMS EVALUATED

The use of wet gas as the flowing medium in a linear test cell with gel filter cakes present is a new step being used in attempting to realistically model in situ reservoir conditions in fracture conductivity measurements. Four fluid systems have been investigated where direct comparative tests were made. That is, identical tests have been conducted where the only difference was the use of 2% KCl brine throughout one test, but only for the first 24 to 50 hours in the other test prior to switching to wet gas flow.

The three fluid systems are (1) polymer emulsion fluid, (2) linear hydroxypropyl guar (HPG) gel, (3) HPG crosslinked with a titanate, and (4) HPG crosslinked with a titanate and containing 5% diesel. Detailed descriptions of these fluids are given below.

Fluid 1: Water external emulsion containing 67% diesel and 33% gelled water (40 lb HPG, 0.1 lb Sodium Persulfate (SP), 5 gal anionic emulsifier per 1000 gal of 2% KCl water buffered to a pH of 6 to 7).

Fluid 2: 40 lb HPG and 0.1 lb SP per 1000 gal of 2% KCl water buffered to a pH of 6.5 to 7.

Fluid 3: 40 lb HPG, 1.2 gal delayed titanate crosslinker, and 0.1 lb SP per 1000 gal of 2% KCl water buffered to a pH of 7 to 7.5. In some tests, 5% diesel and 0.25% surfactant (dispersant) were added.

Fluid 4: Same as Fluid 3 except 5% diesel and 0.25% surfactant (dispersant) were added.

DISCUSSION OF CONDUCTIVITY TEST RESULTS

For many years it was nearly impossible to make meaningful comparisons of laboratory conductivity data generated by two different investigators when using different test cells and possibly different test procedures. In 1978, the API Subcommittee on Evaluation of Well Completion Materials formed a task force to create a new "recommended practices" publication for the purpose of defining laboratory testing methods for evaluating proppants. The years of hard work resulting from that effort have given us API RP 56[22] to evaluate frac sands and two other tentative RP's that are nearing completion. One will be for evaluating high strength proppants[23] and the other for laboratory measurements of proppant pack conductivity.[24] It appears that the RP for measuring proppant pack conductivity will give a specific cell design that should be used, but test procedures specified are only for short evaluation test times. In recent years, most investigators have changed to a cell design that uses similar geometry of the proppant pack as given in the tentative RP.[24] This is also the case for the work reported in this paper.

Since the basic cell design has become fairly standard among most investigators, the one remaining variable of consequence is the test procedure itself. Most of the meaningful work published recently has used 2% KCl brine as the flowing medium. This makes it even more critical that tests be conducted with wet gas to verify or question the large data base being developed with KCl brine flow.

In conductivity testing with KCL brine flow, it has been shown that conductivity damage caused by gel filter cakes can be greatly reduced by the inclusion of extremely high breaker concentrations, especially in the fluid used to inject the proppant slurry.[25] Unfortunately, this test procedure is not representative of fracturing applications in field practice. Although a few treatments may use high breaker concentrations during the final stage of a job, only a small percentage of the fracture face would be exposed to this final stage. Also, there is strong evidence that tests conducted at different test temperatures may give different degrees of conductivity damage, which is also thought to be related to the effectiveness of the breaking of ultra high concentrations of gel in the filter cake. Almond and Bland[11] illustrated that the mid-range reservoir temperatures (160°F to 200°F) where oxidizing breakers were used may result in the highest degree of damage from water based gelled fluids. Their data at lower temperatures, where the enzyme breakers were used, indicated less damage than the mid-range temperatures; however, their data for 270°F (where only thermal degradation is necessary) had distinctly the lowest damage levels.

All fluids used in this project contained breaker concentrations representative of field usage for the fluid system being tested. This is a very important part of the testing procedure.

In a few cases it was necessary to hold a certain stress for more than 100 hours before a steady state conductivity was reached. This is illustrated best in Fig. 5 where more than 150 hours were required for the conductivity to stabilize after the flow was changed to wet gas for the linear gel system filter cake tests. This behavior is contrasted by the results for the polymer emulsion system (Fig. 6) where the conductivity jumped within hours to the steady state value when flow was changed to wet gas. These two figures are for different fluid systems and the wet gas flow was initiated at different points during the life of the tests. Explanations for this varied behavior after changing to wet gas are still subject to further experimentation. For the polymer emulsion system the only direct comparison currently available is the data at 4,000 psi as shown in Fig. 6.

In Figs. 7, 8, and 9 each data point on these graphs represents a test time of 50 hours or more at each stress level. Data shown on these figures offer direct comparisons for test results at least three stress levels for Fluids 2, 3 and 4 described earlier. The one most obvious feature present in all three of these comparisons is the significantly higher conductivities measured when wet gas was used as the flowing medium for most of the test duration. This is thought to be primarily the result of a drying effect, even through the nitrogen gas is being pre-wetted with water prior to entering the conductivity cell. This may have a "shrinking" effect on the gel filter cake, thus improving the porosity of the proppant pack. In most cases the measured conductivity was sharply higher within a matter of 2 to 6 hours after changing from KCl brine to wet gas. The one notable exception was the test following the linear gel system (Fig. 5). Since this occurred at such a low stress (1,000 psi) there was no crushing of the sand. The change was to higher and higher conductivity values, with the appearance that "cleanup" of some nature was occurring. There was always some water found in the trap at the cell exit when it was drained (at least daily). This condensate indicated the nitrogen was carrying more vapor than it could hold at 90°F, which was the typical temperature of this chamber. Even so, the proppant bed was always dry when the cell was disassembled at the end of the test. In all cases the filter cake was more dehydrated when the wet gas flow was used than in tests using brine water only. In some instances the filter cake still maintained a rubbery consistency and in other cases it was very dry. There were fresh traces of diesel being found in the trap even 10 days after the start of the wet gas flow in the test using the emulsion fluid. This was also the case, to a lesser extent, in the wet gas tests on the crosslinked HPG gel when 5% diesel was used.

To demonstrate the importance of the difference in conductivity test results from the "brine only" tests and the "wet gas" tests the example well used in the introduction will be used again. The fracturing design simulator was run with the well information in Table 1 and the treatment fluid and conditions from Table 2. The bottom curve in Fig. 8 was used for the basis of the conductivity values in the simulation. The results of this simulation was that a five-fold production increase could not realistically be obtained. To achieve the necessary fracture conductivity the job would have to use proppant concentrations in excess of 24 lb/gal and have a propped width of more than 1.5 in. When conductivity data from the top curve in Fig. 8 were used the necessary treatment was still very ambitious, requiring up to 14 lb/gal of proppant slurry at the end of the treatment, but it was at least a possibility. The treating schedule required for the simulator to product a five-fold production increase using the "wet gas" data is given in Table 5.

SUMMARY

It has been shown by several investigators that proppant bed conductivities can be much lower than was believed as recently as two years ago. This can be modeled when laboratory tests begin to reflect the real environment that exists in a propped fracture placed by a hydraulic fracturing treatment.

Realistic modeling of fracture conditions is necessary if valid conductivity measurements are to be obtained. Fracture design simulators and production simulators require these data to make predictions for optimization of investment. Although this requires extensive equipment and long test times, the tests must incorporate the effects of the filter cakes deposited during leak-off of the fracturing fluid.

When wet gas was used as the post-cleanup flowing medium, the measured conductivities were higher than when only KCl brine was used. This must be investigated in greater detail and over a broader range of test temperatures.

Future investigations should consider using liquid hydrocarbons to see if oil reservoirs are being accurately modeled by using KCl water as the flowing medium in conductivity testing.

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Table 1
Well and Formation Data

Young's modulus	5.00E+06	psi
Permeability	0.5000	md
Porosity	22.0	pct
Reservoir fluid compressibility	8.50E-05	1/psi
Reservoir fluid viscosity	0.02	cp
BHTP	7800.	psi
Reservoir fluid pressure	4000.	psi
Closure stress	6000.	psi
Gross fracture height	60.	ft
Net fracture height	40.	ft
Wellbore diameter	8.00	in.
Drainage radius	1320.	ft
Well spacing	160.	acres
Bottomhole temperature	200.	deg F

Table 2
Fluid and Treatment Data

Gel type	Crosslinked HPG	
Gel concentration	40#/Mgal	
Injection rate	15.0	bpm
Shut-in period	14.0	hr
Flowback rate	0.5	bpm
Treatment fluid sp gr	1.030	
n'	0.5000	
K' (slot)	0.060000	lbf-sec$^{n'}$/sq-ft
Ceff - fluid-loss coef	0.00180	ft/SQRT (min)

Table 3

Proppant Schedule for Five-fold Production Increase
Based on Short-Time Fracture
Conductivity Data

19,000 gal pad volume
10,000 gal with 1.00 lb/gal
20,000 gal with 2.00 lb/gal
10,000 gal with 3.00 lb/gal

59,000 gal total fluid
800 sacks 20/40 Ottawa sand

Propped Length: 815 ft
Average Fracture
Proppant Concentration: 0.82 lb/ft^2

Table 4

Proppant Schedule for Five-Fold Production Increase
Based on Long-Time Fracture
Conductivity Data

21,000 gal pad volume
5,000 gal with 1.00 lb/gal
5,000 gal with 2.00 lb/gal
5,000 gal with 3.00 lb/gal
5,000 gal with 4.00 lb/gal
20,000 gal with 5.00 lb/gal

61,000 gal total fluid
1,500 sacks 20/40 Ottawa sand

Propped Length: 855 ft.
Average Fracture
Proppant Concentration: 1.47 lb/ft^2

Table 5

Proppant Schedule for Five-Fold Production Increase
Based on Conductivity Data in Top Curve
(Wet Gas Data) in Figure 8

25,000 gal pad volume
4,000 gal with 1.00 lb/gal
4,000 gal with 3.00 lb/gal
4,000 gal with 5.00 lb/gal
4,000 gal with 8.00 lb/gal
10,000 gal with 12.00 lb/gal
12,000 gal with 14.00 lb/gal

63,000 gal total fluid
3,560 sacks 20/40 Ottawa sand

Propped Length: 930 ft
Average Fracture
Proppant Concentration: 3.16 lb/ft^2

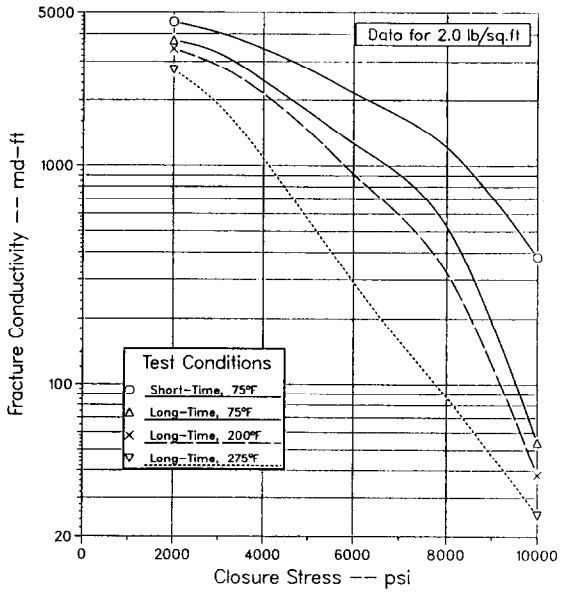

Figure 1 - Conductivity data for 20/40 Ottawa sand showing measured values from short-time test procedures to be overestimated

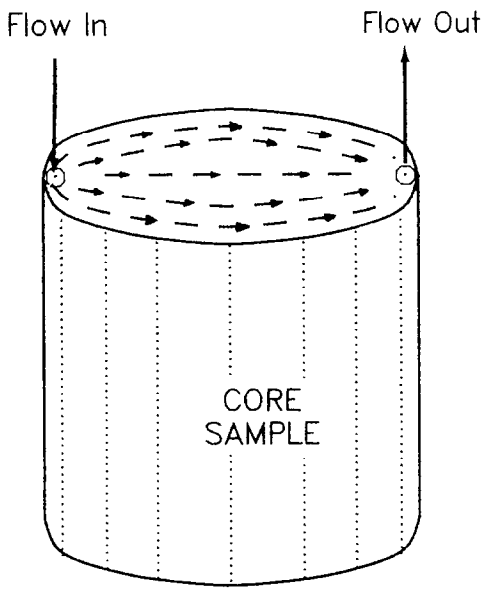

Figure 2 - Probable flow streamlines inside the proppant pack in a cell where cylindrical core with a proppant pack on top is held in a Hassler sleeve type cell

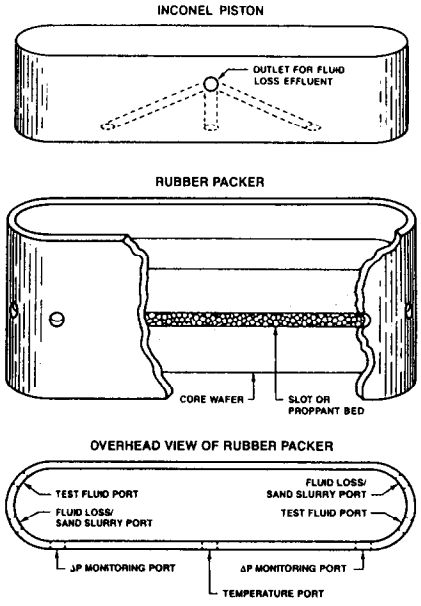

Figure 3 - Schematic showing one of the two pistons and a cutaway view of the core wafers inside the packer of the conductivity/ fluid loss test cell used

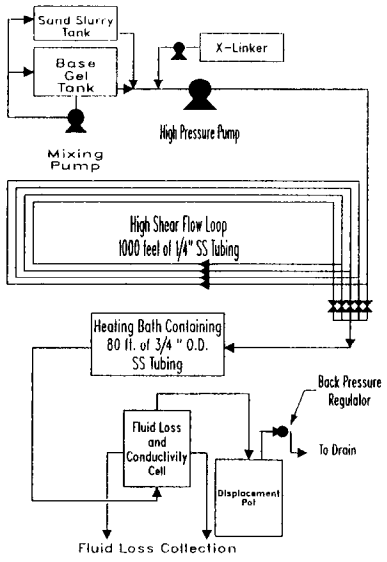

Figure 4 - Fluid preconditioning loops and dynamic fluid loss / conductivity apparatus

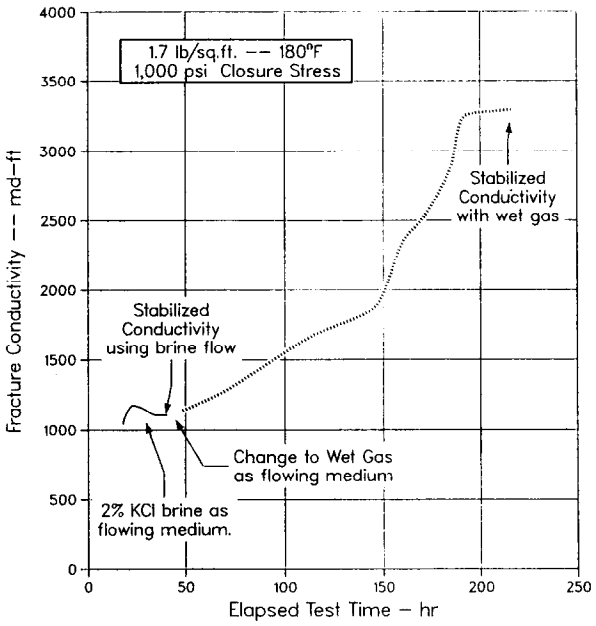

Figure 5 - Conductivity vs time for 20/40 Ottawa sand in the presence of filter cakes from a linear gel system containing 40 lb HPG per 1000 gal.

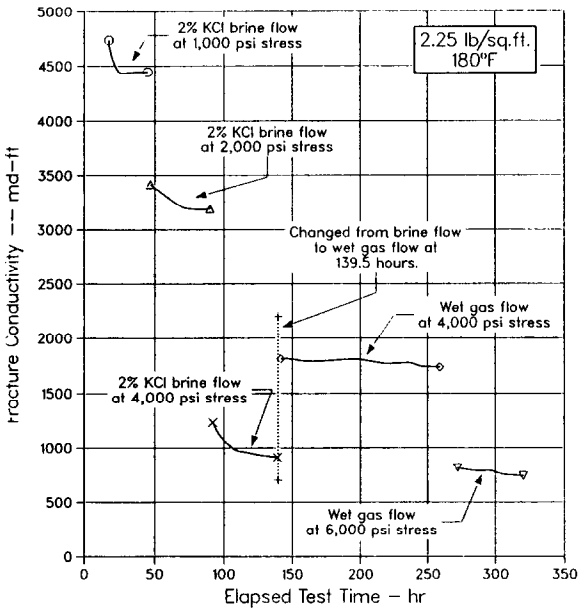

Figure 6 - Conductivity vs time for 20/40 Ottawa sand in the presence of filter cakes from a polymer emulsion fluid using 2% KCl brine flow then wet gas flow

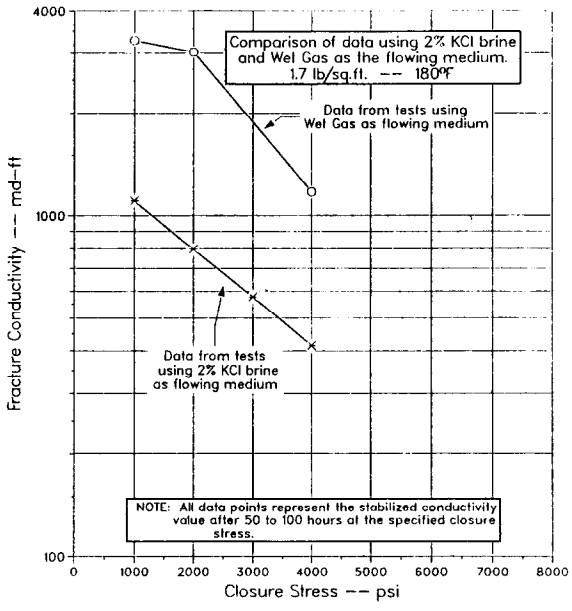

Figure 7 - Conductivity vs stress for 20/40 Ottawa sand in the presence of filter cakes from a linear HPG gel (40 lb per 1000 gal.)

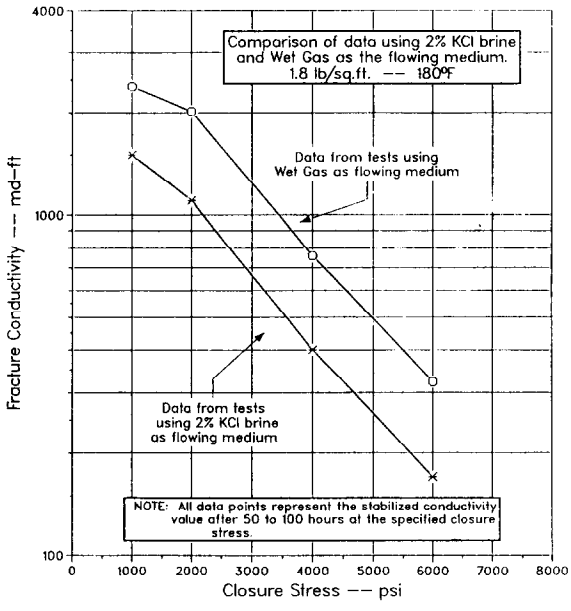

Figure 8 - Conductivity vs stress for 20/40 Ottawa sand in the presence of filter cakes from a crosslinked HPG gel

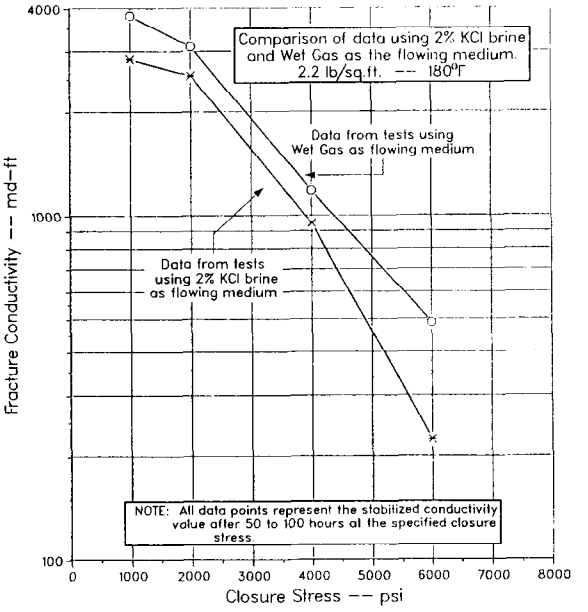

Figure 9 - Conductivity vs stress for 20/40 Ottawa sand in the presence of filter cakes from a crosslinked HPG gel containing 5% diesel and 0.25% dispersant