FLUID DESIGN TO MEET RESERVOIR ISSUES-A PROCESS

J.MASIKEWICH B.BENNION

this article begins on the next page ☞

Fluid Design to Meet Reservoir Issues—A Process

J. Masikewich
Q'Max Solutions Inc.
B. Bennion
Hycal Energy Research Laboratories Ltd.

This paper is to be presented at the 48th Annual Technical Meeting of The Petroleum Society in Calgary, Alberta, Canada, June 8 – 11, 1997. Discussion of this paper is invited and may be presented at the meeting if filed in writing with the technical program chairman prior to the conclusion of the meeting. This paper and any discussion filed will be considered for publication in CIM journals. Publication rights are reserved. This is a pre-print and is subject to correction.

ABSTRACT

As open hole completion's, horizontal wells, multi-laterals and underbalanced drilling become more common place, greater emphasis is being placed on the selection and design of drilling and completion fluids. The problem of assessing fluid compatibility with hydrocarbon reservoirs is ongoing and usually unique to each reservoir. This problem becomes most visible after resources have been expended to drill, with unsatisfactory results in productivity.

The objective of this paper is to present a process designed to use the best available methodologies and laboratory techniques to assist in the design and selection of fluids which will be most compatible with the reservoir. Ultimately the goal is to drill zero skin wells. The process addresses fluid design issues from both a bridging or solid phase perspective and a liquid phase perspective. Optimization relative to design such as chemical selection and concentrations are an integral part of the process.

Using this process will reduce uncertainty regarding fluid selection and the impact of the fluids on productivity. Ultimately it is meant to assist in both increasing well productivity and reducing the requirement for expensive stimulation. The process may lead to innovation - resulting in new systems or products. It may be applied when designing workover and completion fluids or for drill-in fluids including overbalanced or underbalanced applications.

INTRODUCTION

The potential to reduce wellbore productivity while conducting drilling completion and workover procedures has been addressed extensively in petroleum related literature. Productivity impairment was originally recognized in field cases where development wells produced only small volumes of fluid upon completion or where producing wells produced less after work-over procedures. In other instances, where drill stem tests taken while drilling deep wells indicated potentially good production from shallow zones, difficulty was experienced in attaining production from those zones which had remained in contact with drilling muds for an extended time.[1] Investigations of specific damage mechanisms is an ongoing pursuit. Bates *et al* discussed the influence of clay content on water conductivity of oil sands in 1946.[2] Nowak *et al* studied the effect of mud filtrates and mud particles on permeability in 1951.[3] Various models which consider formation damage have quantifiable outputs such as Skin Effect,[4] Productivity Index[5] and Formation Damage Index Number.[6] Methods of preventing formation damage continue to be tested, developed and documented.

A greater percentage of wells are now designed as open hole completions, where perforating past the damaged zone is impractical. Consequently sophistication in fluids testing procedures has increased and frequently operators test whole fluids against their rock. Often fluid samples are obtained from multiple sources. Return permeability tests[7] are regularly used to select the "best" fluid. Unfortunately, if an adequate candidate isn't found, the data are usually insufficient to redefine the direction testing should take. The process described herein helps to categorize and quantify discrete damage mechanisms. Fluid design is systematically optimized for all damage issues such that ultimately the fluid is compatible with the reservoir.

In actual practice the first line of defense against formation impairment is to keep foreign fluids and solids out of the rock. Thus, when drilling overbalanced, designing an efficient sealing cake or "bridging system"[8] becomes essential. However the very nature of bridging systems denotes spurt loss associated invasion. Further, since the efficiency of any bridging system diminishes due to both mechanical degradation and through pore throat heterogeneity, only the effective design of the base fluid will provide assurance that the best overall fluid was chosen to drill the reservoir.

ASSUMPTIONS

The focus when designing any fluid whether it is ROP, borehole stability or reservoir compatibility may be subordinated to other criteria such as cost, safety, environmental acceptability and operational feasibility. The process described in this paper functions independently from other design criteria - assuming they have been met and the net result is a safe, acceptable fluid. Further, the efficient execution of the process depends on the quality of the team implementing it. A cross functional team or asset team should be assigned to the project. Representation should include geology, reservoir, geophysics, production, completions and drilling as well as special core analysis and drilling fluids expertise.

REVIEW OF FORMATION DAMAGE MECHANISMS

Common formation damage mechanisms have been categorized in different manners by various authors.[9] They include:

Fluid - Fluid Interactions

Emulsion blocking - a viscous suspension of two immiscible fluids (usually oil and filtrate) which physically restricts flow. Emulsions may be stabilized by drilling fluid components, particularly oil-wet ultra fines, or asphaltenes.

Precipitates and Scales - caused by incompatibilities between filtrates and connate fluids or by dissolution/precipitation of mineral grains. Some precipitates which could cause physical plugging include: $CaSO_4$, $CaCO_3$, CaF_2, $BaSO_4$, $SrCO_3$, $SrSO_4$.

Parrafins and Asphaltenes - especially associated with underbalanced drilling where the reductions in temperature and pressure associated with the production of crude oil result in asphaltic or waxy sludges being deposited on or in the near-wellbore pore throat system. Asphaltenes act as cationic particles with a potential to oil-wet rock. Mixing of incompatible oil-based filtrates with in-situ liquid hydrocarbons may also result in de-asphalting of the produced crude oil in some situations.

Fluid - Rock Incompatibilities

Migrating Clays - kaolinite has a tendency to shear away from pore throat walls and migrate and plug if interstitial velocities and electrolytic conditions are adverse (i.e., pH above 8.5 or low salinity). Other loosely attached in-situ clays or fines may also be susceptible to migration.

Swelling Clays - include smectites and mixed layer clay which expand when contacted by fresh or low salinity water-based filtrates.

Phase Trapping/Blocking - refers to adverse relative permeability effects associated with the retention of invaded aqueous or hydrocarbon fluids.

Chemical Adsorption/Wettability Alteration - some polymers in water-based fluids and surfactants in oil-based fluids are able to physically adsorb onto rock surfaces plugging pore throats (due to their large size) or altering wettability, substantially reducing permeability.

Solids Invasion - when pulverized drilled solids or commercial solids (clays, weighting or bridging solids) become fine enough to enter into the pore throat system, permanent plugging can result.

Other damage mechanisms - include grinding and mashing of solids by the drill string, spontaneous counter current imbibition effects[10] and glazing and surface damage effects caused by insufficient heat conductive capacity of circulating fluids.

THE PROCESS

A process is "a series of actions, changes or functions bringing about a result". The steps are as follows:

Step 1. Identify the characteristics of the fluid-rock system.

Step 2. Postulate relative to the presence and severity of discrete impairment mechanisms.

Step 3. Validate and quantify the impairment mechanisms.

Step 4. Design and optimize to mitigate all impairment mechanisms.

Step 5. Design the bridging system if required.

Step 6. Test and select whole fluid.

A chart depicting the process is shown at the end of this paper (Figure 1).

Step 1: Identify the characteristics of the fluid-rock system.

The first step is to secure all available data relative to the reservoir. In producing fields, most of the data is often available - it's just a matter of assembling it. This is usually the case when designing for horizontal wells. In some instances relatively inexpensive testing may be required to complement existing data. At this point the relevance or importance of data to the fluid system design may not be apparent. The following information should be assembled prior to commencement of step 2:

1. Reservoir rock type: limestone, dolomite, sandstone, conglomerate.
2. Reservoir type: oil, heavy oil, gas, gas condensate.
3. Depth: true vertical depth.
4. Temperature.
5. Pressure: from offset DST's, AOF measurements or stabilized shut in pressures from offset wells.
6. Porosity/Permeability: charts should be available from routine core analysis done on close offset wells. Figure 2 provides a typical example of this.
7. Pore throat size curves are available from mercury injection capillary pressure analysis (Figure 3) or SEM analysis - which is possible to conduct using only a rock chip or drill cutting.
8. Wettability analysis: USBM/AMOTT capillary pressure/wettability test. Figure 4 shows a typical example of the results of this test.
9. *In-situ* fluid saturations: initial water saturation (Swi) and initial oil saturation (Swo) obtained from low invasion cores or accurate log analysis.
10. Fluids analysis: both connate water and oil analysis are important in predicting incompatibilities. Often "synthetic" formation brine is used for laboratory compatibility testing if connate water isn't available. Figure 5 depicts a typical water analysis.
11. In most reservoirs, especially sandstones, it is essential to quantify the presence of clay and other fine particulates. This is best achieved using one or a combination of X-Ray diffraction (XRD) - see Figure 6, scanning electron microscopy (SEM) and thin section petrography. XRD analysis is usually used first to detect and quantify the presence of clays because it is inexpensive. More stringent investigation of the nature and association or condition of clay minerals or other particulates can be facilitated by studying thin section or SEM micrographs.
12. The presence of acid gas may dictate the need for specialized fluid ingredients such as scavengers, alkalinity additives or corrosion control products.
13. Knowing the reservoir history, completion /stimulation plan or other pertinent information may lead to alterations in fluid design. For example acid stimulation as a completion technique may not be an option if the well path is in close proximity to the water contact. This may reduce the benefit of using an acid soluble bridging system. Or if plans include running a wire-wrapped screen, a cellulose "matting system" might incorporate a carefully selected enzyme breaker to degrade the cellulose.

Step 2: Postulate relative to the presence and severity of discrete impairment mechanisms.

Once the characteristics of the reservoir have been assembled, the entire team can discuss the probability of specific damage mechanisms occurring. Assistance with this step may be acquired in a number of ways. Networking with other experts is often profitable. Wall charts such as Core lab's "Formation Damage Assessment and Control chart", SynerTech's "Reservoir Sensitivities of Alberta Sandstone Formations" or tables such as Table 1[9] or Table 2[10] by Bennion *et al* are often helpful. At this point true consensus isn't required because individual theories are *tested* at the next step.

Step 3: Validate and quantify the impairment mechanisms.

At this point samples of reservoir rock, oil, connate water and make-up water, can be collected for testing. When collecting oil and water it is essential to gather *untreated* samples. Often connate water must be synthesized - this is acceptable as extremely close replications are possible.

Most design programs incorporate "special" core analysis requiring small core plugs - usually 3.81 cm in diameter x 4-7.5 cm in length - to be cut from full diameter cores. Typically better quality rock is selected, since the majority of fluids will be produced from this rock. Careful selection and restoration of the plugs is a pre-requisite for effective special core analysis. Magnetic resonance imaging is a recommended technique for screening core plugs. This is because sandstone plugs with similar permeability and porosity may have markedly different internal characteristics including laminations and cross - bedding or they may even be impermeable on one side. MRI imaging of carbonate plugs clearly shows vugular hetrogenieties as well as the nature and length of the fractures within the plug. Figure 7 depicts a typical MRI image of a fractured core plug. Note the lateral "thin section" images taken along the length of the plugs.

Since preserved cores are seldom available, it is usually necessary to restore extracted core plugs to their original wettability and water/oil saturations. This procedure is conducted at reservoir temperature, using real reservoir fluids. This may require 6 - 8 weeks for oil reservoirs and somewhat less time for gas reservoirs. Therefore the project time line should be constructed to account for this restoration time.

Emulsion testing should be performed wherever there is a possibility of filtrate mixing with oil. API RP 42 is a simple procedure which can be used in the lab or the field to test for emulsions. Water (25 ml) and oil (75 ml) are mixed together with fine solids and stirred at 14,000 RPM for 30 seconds. The emulsion is poured into a 100 ml cylinder and volumes of water breakout are recorded at various time intervals. This procedure is sometimes modified in that it is conducted at reservoir temperature and occasionally without the solids.

Filtrate - Connate Water Compatibility Analysis should be conducted, if the water analysis indicates dissolved solids. This involves combining the two samples in equal proportions and raising the temperature to reservoir temperature while stirring slowly. If precipitates are not observed, the test should be continued by raising the pH with sodium hydroxide. Computer software is also available to conduct this type of work in an analytical fashion.

Oil - Oil Compatibility Testing should be done if an oil continuous fluid is a candidate for drilling. This test measures the particulate population when varying ratios of crude oil and base oil are combined. The objective of the test is to insure that the actual sum of the particulates in the combined fluid does not exceed the calculated sum. Typical test results are shown in Figure 8.

Clay Migration Testing, sometimes called a critical velocity test uses a small core plug, restored as previously described. The plug is mounted in a holder where reservoir conditions including stresses, temperatures and pressures may be simulated. In this test an inert fluid such as formation brine is passed through the core in a series of increasing velocities. The permeability to the fluid is measured at each flow rate. The critical velocity is that velocity where mobile fines such as bitumen or kaolinitic clays begin to dissociate or to shear off pore walls, plugging the pore throats. A change in permeability will occur at the critical velocity. The relative impact of this velocity on well productivity may be extrapolated by comparing rates of fluid leak-off in regain permeability tests or by calculating interstitial velocities at expected production rates. Figure 9 shows graphically the results of a critical velocity test.

Clay Swelling Testing, uses a restored core plug mounted in a manner similar to that described for a critical velocity test. A baseline permeability to (usually saline) formation brine is established after several pore volumes have passed through the plug. Sensitivity to fresh water due to swelling clay is measured as a reduction in permeability when fresh or low salinity water is passed through the core. If the permeability hasn't been shut off completely, the baseline permeability can usually be re-established by switching back to formation brine. This increase back to baseline permeability would indicate that dissolved salts are aggregating the hydrated clays - causing them to occupy less space in the pore throat system. Figure 10 graphically depicts typical clay swelling test results. Many clays can also deflocculate if electrostatic equilibrium which is holding the clays bound in place are disrupted by increases in pH or reduction in system salinity.

Phase Trap Testing [11] can quantify the relative permeability effects associated with the retention of water or oil. To do the test, a core plug is restored to its *in-situ* wettability and fluid saturation's. In an aqueous phase trap test, the plug is restored to a sub-irreducible water saturation. The plug is mounted in a core holder where reservoir conditions are simulated. Permeability to gas is measured. The plug is slowly injected with produced brine, establishing irreducible water saturation. Permeability to gas is then measured again, at pressure resembling the available drawdown at reservoir conditions. If the second permeability is lower, damage due to phase trapping alone has been quantified. Figure 11 shows the results of a phase trap test.

Wettability Testing may also be conducted after API RP 42 to insure that surfactant treatments leave the rock in their natural state. The procedure varies depending on whether the surfactant is water soluble or oil soluble. Since not all rocks will exhibit strongly water-wet or strongly oil-wet character, the results of this type of test may be difficult to interpret.

Step 4: Design & optimize to mitigate all impairment mechanisms.

The objective at this stage in the process is to select the two or three best available methods for mitigating each identified damage mechanism and test them against each other. Starting points relative to concentrations or properties should be based on experience. When one method is shown to be the best, the next step is to optimize the concentration. For example in the emulsion test previously described, if a stable emulsion is noted, the test should be repeated with different demulsifiers added to the filtrate before mixing. Once the most effective demulsifier is identified the concentration should be optimized in order to tell if more is better or if less is just as effective.

When dealing with precipitate problems the chemistry may be complex. It is often advisable to procure supplier expertise, however the same steps in the process apply.

Migrating clays can be controlled to a degree by controlling alkalinity, with the addition of certain polyvalent metal ions, and by controlling the rate at which fluids flow through the pore throat system - by enhancing fluid filtration control properties and by bringing the well on gradually during the production process.

Swelling clays can be controlled with certain cations or polymers. A clay swelling test may be extended to include flooding the core with one or more possible candidate clay stabilizers and charting the results as depicted in Figure 10. Note how the cation actually improves permeability by dehydrating the swelling clays. Again the object is to determine not only the best remedy, but also its most cost-effective concentration or application.

Phase trap mitigation may require the proper application of a surface tension reducing additive such as a surfactant or alcohol. In some instances of aqueous phase trapping, a base oil may offer the best results.

Wettability - if API RP 42 wettability testing indicates an adverse reaction to any surfactant such as a defoamer or torque reducer, testing should be conducted to determine a suitable replacement.

At the end of this step in the process the components of the candidate fluid(s) should be selected. In tight, complicated reservoirs the testing results may be less than what had been hoped for. This may lead to the selection of an alternate base fluid such as an oil or an alternate method such as underbalanced drilling. However the benefits of the study can be applied to underbalanced drilling or to future reservoir work, including EOR work.

Step 5: Design the bridging system if required.

When fluid contacts the formation there is a spurt loss of whole fluid which continues until solid bridging particles block the pore throats. A properly designed filter cake has three basic layers.[12] The primary bridge consists of large particles and is formed with the initial spurt loss. The secondary bridge is formed as smaller bridging solids mixed with colloidal particulates layer over the top of the primary bridge. The final seal is a polymer film.[12] The construction of this thin, impermeable cake (less than 1.5 mm thick in properly designed fluids) proceeds rapidly as progressively smaller granular particles pack tightly into any remaining openings.

In 1977 Abrams[13] concluded that: "Muds that contain bridging material that meets the 1/3 rule for bridging impairs rock to depths less than 1 inch. The rule requires that the mud must contain bridging material with diameters greater or equal to 1/3 the formation median pore size at concentration levels of at least 5 % by volume of the mud solids. In 1980 Mahajan[8] recognized that fluid loss polymers enhanced bridging efficiency and provided better return permeability in an HEC/sized carbonate fluid. He also pointed out that other work concluded that relative to HEC/calcium carbonate solutions the one third rule "might not hold." The draw back to the rule is that it refers to median pore and particle sizes as opposed to distribution curves. In general broader distribution curves are most efficient.

Figure 12 shows the resolution attained when a pore throat size distribution curve is compared to a particle size distribution curve. The most efficient concentration of bridging solids will to a degree depend on how tight the reservoir is. Effective shut-off (i.e. no down hole losses) can be achieved with as little as 1.0% (w/w) sized carbonate. In more porous rock, up to 5.0% may be needed.

Bridging on fractures is a more difficult matter. Loeppke *et al*[14] studied bridging at the fracture face. Their data suggests that a slot (fracture) size:particle size ratio of 0.8 to 1.0 at a concentration of 1.5% - 4.5% w/w was efficient for bridging fracture faces. This pertained to blocky materials - where particle size means that 95% of the particles were less than that size.

Sharma[15] recommended using low annular velocities to deposit cellulose fibres on fracture faces because fibres were more efficient than solid, blocky material. Tietard[15] proposed a method of using real time LWD of natural fracture width to determine the best LCM particle size distribution.

The nature of the reservoir and the planned completion technique are what drives bridging system design. Sized carbonates are inexpensive and commonly used in both water and oil-based systems in all types of reservoirs where HCL treatments are possible to conduct. Close attention should be paid to the quality (ie. acid solubility) of the product. A disadvantage to using carbonates is that they are not soluble in formation fluids. Thus if fine particles are lost too far back into the formation during high loss periods, they may be beyond the reach of acid. Calcium carbonate is thermally stable and has a specific gravity of 2.7.

Sized oil soluble resin particles are used in water-based systems for drilling both carbonate and sandstone oil reservoirs. Resin has an advantage in that it eventually dissolves even when carried back into the reservoir. Typical resin has a softening point of 162°C and a sp gr of 1.02. The solubility of resin should always be tested using "live" crude from a close offset well.

Sized salt (NaCl) systems can be used in all reservoirs containing some connate water. They may be carried either in viscosified oil or in salt saturated water. Salt is thermally stable with a sp gr of 2.18.

Cellulosic fibres make extremely effective sealants. However fibres are only about 40% soluble in acid. Therefore caution is advised prior to use in fractured reservoirs or where a slotted liner will be run. Fibre cakes rely mainly on drawdown, requiring a physical push from formation fluids for removal. Therefore they may not be applicable in gas wells where drawdown is less than sufficient. Some suppliers are experimenting with enzymes which "break" cellulose fibres.

Table 3 shows some bridging materials and their relative sizes while Table 4 depicts a bridging material selection chart.

Step 6: Choose & test whole fluid

Choosing the whole fluid is a matter of combining the one or two best candidate bridging systems with one or two of the best base fluid candidates. Regain permeability testing is conducted using core plugs that have similar characteristics. The test involves mounting a restored core plug in a holder and applying overburden stresses at reservoir temperature. A baseline permeability to the oil or gas is established by flowing it in direction D_1. Drilling fluid is then flowed across the face of the plug at overbalance pressure such that filtrate penetrates the plug in direction D_2. The volume of fluid lost versus time is recorded and plotted. Finally, the flow of formation fluid is again directed through the plug in direction D_1. The permeability is again calculated showing any reduction attributable to the mud. The results of these tests allow a quantifiable comparison of more than one drilling fluid system on the reservoir rock. Figure 13 shows a schematic of a typical apparatus used for reservoir condition, overbalanced drilling fluid evaluations. There have been several important advancements in laboratory evaluation techniques recently[17]. They include:

1. Dynamic leakoff testing where fluids are able to flow across the face of the core.
2. Full diameter and crossflow leak-off apparatus which provides up to 40 times the exposed cross sectional area for work on highly heterogeneous rock.
3. Techniques for artificially inducing fractures.
4. Apparatus to simulate underbalanced drilling.
5. Threshold pressure regain procedures - designed to determine both the point at which formation fluids initially penetrate the damaged rock and the permeability expected at the maximum expected drawdown gradient.
6. Pressure tapped cores which allow for the evaluation of sectional permeabilities.
7. Spontaneous imbibition tests - designed to measure counter current imbibition of drilling fluid into the reservoir while maintaining underbalanced conditions.

Figure 14 shows a typical presentation of regain test results while Figure 15 indicates the rate and the calculated depth of fluid invasion into the core. Note the units on the y axis are converted to "field" units. After the test has been conducted, a simulated stimulation can be conducted on the plug. This might include an underbalanced acid wash or an acid squeeze. Saving the core for petrographic analysis after the test may indicate the actual depth of invasion of particulates or the dislocation of reservoir fines.

Damage mechanisms which are difficult to simulate and test for include damage caused by:

1. Bacterial growth. (Long term testing required.)
2. Grinding and mashing of fines into near wellbore pore throats by drillstring rotation.
3. Glazing caused by inefficient heat removal.

BRIEF CASE STUDY #1: PANCANADIAN PETROLEUM "GLAUCONITIC"

The details of this study have been previously published.[18]

Formation Characteristics:

Rock Type:	Sandstone
Reservoir Type:	Gas
Depth	1,850 mMD
Pressure:	15.5 mPa
Permeability:	1-10 mD
Porosity:	8-14%
Median Average Pore Throat Size:	2-7 µm
Swi (average)	35%
Swirr (average)	39%

Illite-Smectite:	trace to 12% of Clay Fraction

Postulation:

The team agreed that the issues in this reservoir would be clay swelling and aqueous phase trapping.

Validation:

Two avenues of validation testing were pursued.

1. Phase trap testing indicated 85% damage due to phase trapping.
2. A clay swelling test resulted in a permeability reduction to fresh water (from 0.25 md to 0.18 md).

Optimization:

1. Testing against the aqueous phase trap included trying oil, alcohol and IFT reducers with 5% n Butyl alcohol proving most cost effective.
2. Clay swelling tests were continued with clay stabilizers including potassium acetate and a 3% potassium chloride solution. When the potassium chloride proved to be the best stabilizer, further tests were conducted to determine if 6% was better or if 1% was just as effective.

Bridging system design and whole mud testing

This series of wells were drilled underbalanced with N_2 misted with 3% KCl water. Therefore further testing and a bridging system were not required. Some stimulation was conducted using 5% n-Butyl alcohol.

BRIEF CASE STUDY #2: CABRE EXPLORATION LTD. "CARDIUM"

Formation Characteristics:

Rock Type:	Sandstone
Reservoir Type:	Oil
Depth:	1,200 mMD
Pressure:	8,900 kPa
Permeability:	2-6 mD
Porosity:	8-12%
Swi:	15%
Swirr:	35 - 50%

Tests that were conducted during the study to assist in the design provided the following additional characteristics:

Bulk Analysis:	6% total Clay
Chlorite/Mixed Layer:	TR-1.8% of Clay Fraction
Kaolinite:	52% of Clay Fraction
Thin Section Analysis:	Trace swelling clay, migrating fines potential
USBM/AMMOT analysis:	Strongly water-wet
Throat Size:	4 μm approximately

Postulation:

This team agreed that design would focus around swelling clays and the aqueous phase trap potential.

Validation:

1. Phase trap testing indicated a 30% reduction in flow conductivity.
2. A clay swelling test resulted in nearly a complete shut-off when fresh water was flowed through a core plug.

Optimization:

1. A second phase trap test was conducted using formation brine treated with a surface tension reducing surfactant. The test resulted in a net permeability reduction of 28% - inconclusive when compared to the original test. No further testing was conducted.
2. Two types of clay stabilizer were used to attempt to reduce the effect of clay swelling. The first, a "polyquat" inhibitor actually reduced the permeability by 89%. The second, 3% KCl added to formation brine, increased the permeability by 35% - suggesting the clays were in ionic equilibrium with the formation brine - and that equilibrium is less than 100% stabilized.

Bridging system design and whole mud testing

With this knowledge base, the team agreed to conduct two whole mud leakoff tests on restored core plugs.

The first system, a viscosified mineral oil using a sized salt bridging system and 4% formation microfines yielded a 100% regain in permeability. Total leakoff volume was 8.2 cc's in 240 minutes.

The second system was a water-based system containing 3% KCl and 4% microfines. It was formulated with a sized oil-soluble resin bridging system. This system provided a net decrease in the original baseline permeability of 19%. 3.0 cc's of filtrate leaked into the plug in 240 minutes.

A third system, "Canola oil mud" was supplied by a third party. It isn't known what type of bridging system it had but again 4% microfines were added to the system. This system imparted a net reduction in permeability to the plug of 44%. Leak-off volume was 1.3 cc's in 240 minutes.

CONCLUSIONS

1. A process has been presented which follows an analytical progression of information gathering, discussion, validation of theories and design optimization.
2. Technology is available to allow the process to focus on identification and design around discrete damage mechanisms.
3. Following the process will achieve the objective of assurance for all stakeholders that the best effort has been expended to secure a zero skin well.

ACKNOWLEDGMENTS

The authors wish to thank The Petroleum Recovery Institute and Petro Canada for permission to publish the NMR images used in Figure 1, PanCanadian Petroleum for permission to publish the information in Case Study #1 and Figures 9 and 10 and Cabre Exploration for permission to publish the information in Case Study #2.

REFERENCES

1. P.H. Monaghan, R.A. Salathiel, B.E. Morgan, et al: *Laboratory Studies of Formation Damage in Sands Containing Clays*, Society of Petroleum Engineers (1959) No. 1162-G

2. T.G. Bates., Gruver, R.M. and Yuster, S.T.: *"Influence of Clay Content on Water Conductivity of Oil Sands"*, Oil Weekly (October 21, 1946) 48.

3. T.J. Nowak and R.F. Kreuger: *"The Effect of Mud Filtrates and Mud Particles upon the Permeability of Cores"*, Drill. and Prod. Proc. API (1951) 164.

4. A.F. Van Everdingen: *"The Skin Effect and its Influence on Well Productivity"*, Trans AIME Vol. 198 (1953) 171-176.

5. *"Pseudosteady-State Flow Equation and Productivity Index for a Well With Noncircular Drainage Area"*, Society of Petroleum Engineers (1978) No. 7108.

6. P.B. Basan, NL Erco: *"Formation Damage Index Number: A Model for the Evaluation of Fluid Sensitivity in Shaly Sandstones"* Society of Petroleum Engineers (1985) No. 14317.

7. D. Brant Bennion, F. Brent Thomas, Douglas W. Bennion: *"Laboratory Coreflood Tests to Evaluate and Minimize Formation Damage in Horizontal Wells"*, Presented at the Petroleum Society of CIM Horizontal Well Seminar - The Canadian Perspective, November 18, 1991, Calgary, Alberta, Canada.

8. Naresh C. Mahajan, Bruce M. Barron, Brinadd Company: *"Bridging Particle Size Distribution: A Key Factor in Designing of Non-Damaging Completion Fluids"*, American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., Society of Petroleum Engineers (1980) No. 8792.

9. D. Brant Bennion, F. Brent Thomas, Douglas W. Bennion, Ronald F. Bietz: *"Fluid Design to Minimize Invasive Damage in Horizontal Wells"*, presented at the Canadian SPE/CIM/CANMET International Conference on Recent Advances in Horizontal Well Applications, March 20-23, 1994, Calgary, Canada, No. HWC94-71.

10. D.B. Bennion and F.B. Thomas: *"Underbalanced Drilling of Horizontal Wells: Does It Really Eliminate Formation Damage?"*, Society of Petroleum Engineers, Inc., (1994) No. 27352.

11. D.B. Bennion, R.F. Bietz, F.B. Thomas, M.P. Cimolai: *"Reductions in the Productivity of Oil and Low Permeability Gas Reservoirs Due to Aqueous Phase Trapping"*, JCPT (Nov 1994, Volume 33. No. 9) JCPT94-09-05.

12. Brine-Add literature at http://www.brine-add.com.

13. A. Abrams, Shell Development Co.: *"Mud Design to Minimize Rock Impairment Due to Particle Invasion"*, Society of Petroleum Engineers (1977) No. 5713.

14. Loeppke, Gelan E., David A. Glowka, Elton K. Wright: *"Design and Evaluation of Lost Circulation Materials for Severe Environments"*, Society of Petroleum Engineers (1990) No. 18022.

15. Di Jiao and Mukul M. Sharma: *"Mud Induced Formation Damage in Fractured Reservoirs"*, Society of Petroleum Engineers, Inc., (1995) No. 30107.

16. Olivier Lietard, Tessa Unwin, Dominique Guillot and Mike Hodder: *"Fracture Width LWD and Drilling Mud / LCM Selection Guidelines in Natural Fractured Reservoirs"*, Society of Petroleum Engineers Inc., (1996) No. 36832.

17. D.B. Bennion, F.B. Thomas, R. Bietz and D.W. Bennion: *"Advances in Laboratory Coreflow Evaluation to Minimize Formation Damage Concerns With Vertical / Horizontal Drilling Applications"*, CADE/CAODC Spring Drilling Conference, April 19-21, 1995, No. 95-105.

18. P.L. Churcher, Fred J. Yurkiw, Ron F. Bietz and D. Brant Bennion: *"Properly Designed Underbalanced Drilling Fluids Can Limit Formation Damage"*, Oil and Gas Journal, April 29, 1996.

TABLE 1
Potential Formation Damage Mechanism
in Different Reservoir Types

Damage Mechanism	Fluid-Fluid Incompatibility	Rock-Fluid Incompatibility	Solids Invasion	Phase Trapping	Chemical Adsorption	Fines Migration	Biological Damage	Effect of High Overbalance
Homogeneous Sand-Clean	POSS	POSS	POSS	POSS	POSS	UNL	POSS	POSS
Homogeneous Sand-Dirty	POSS	PROB	POSS	POSS	PROB	PROB	POSS	POSS
Laminated Sand-Clean	POSS	POSS	POSS	POSS	POSS	UNL	POSS	POSS
Laminated Sand-Dirty	POSS	PROB	POSS	POSS	PROB	PROB	POSS	POSS
Unconsolidated Sand	POSS	POSS	PROB	UNL	POSS	POSS	POSS	PROB
Fractured Sand Permeable Matrix	POSS	POSS	PROB	POSS	POSS	POSS	POSS	PROB
Fractured Sand Low Permeability Matrix	POSS	UNL	PROB	POSS	POSS	UNL	POSS	PROB
Homogeneous Carbonate	PROB	UNL	POSS	PROB	POSS	UNL	POSS	POSS
Fractured Carbonate Impermeable Matrix	PROB	UNL	PROB	POSS	UNL	UNL	POSS	PROB
Fractured Carbonate Permeable Matrix	PROB	UNL	PROB	POSS	POSS	UNL	POSS	PROB
Vugular Carbonate	PROB	UNL	PROB	UNL	UNL	UNL	POSS	PROB

PROB Probable damage mechanism under most conditions
POSS Possible damage mechanism under specific conditions
UNL Unlikely damage mechanism under majority of conditions

Source: D. Brant Bennion, F. Brent Thomas, Douglas W. Bennion, Ronald F. Bietz: *"Fluid Design to Minimize Invasive Damage in Horizontal Wells"*, presented at the Canadian SPE/CIM/CANMET International Conference on Recent Advances in Horizontal Well Applications, March 20-23, 1994, Calgary, Canada, No. HWC94-71.

TABLE 2

Initial Permeability to Air (mD)	Severity of Aqueous Phase Trap				
	Sw <10%	Sw 10-20%	Sw 20-30%	Sw 30-50%	Sw >50%
k < 0.1 mD	Severe	Severe	Moderate	Moderate	Mild
0.1 < k < 1 mD	Severe	Moderate	Mild	Mild	Slight
1 < k < 10 mD	Severe	Moderate	Mild	Slight	Unlikely
10 < k < 100 mD	Moderate	Mild	Slight	Unlikely	Unlikely
100 < k < 500 mD	Mild	Mild	Unlikely	Unlikely	Unlikely
500 mD+	Slight	Unlikely	Unlikely	Unlikely	Unlikely

Permeability reductions associated with definitions:

Severe = greater than 90% reduction in oil/gas permeability
Moderate = 50-90% reduction in oil/gas permeability
Mild - 20-50% reduction in oil/gas permeability
Slight = 0-20% reduction in oil/gas permeability
Unlikely - permeability reduction unusual

TABLE 3
Bridging Materials and Their Relative Sizes

PRODUCTS	MICRONS (minimum)	MICRONS (maximum)	D50	MAX MESH
100 Mesh Resin	1	140	24	100
30 Mesh Resin	1	541	40	30
4 Mesh Resin	1	4760		4
Fine Salt	10	300	80	40
Medium Salt	100	1100	450	16
Coarse Salt	800	10000	3000	7/16"
Carbonate - Micro	1	22	3.5	325
Carbonate - 325	1	44	9	325
Carbonate - Bridgit XF	1	125	25	100
Carbonate - Fine grind	1	350	82	40
Carbonate - Zero grind	1	500	88	30
Carbonate - Supercal	88	840	451	20
Carbonate - Bridgit F	176	2000	506	10
Carbonate - Feed Grit	500	2000	1076	10
Carbonate - Poultry Grit	500	4760	1752	4
Carbonate - Bridgit M	480	4800		4
Carbonate - Bridgit C	3300	6300		1/4"
Carbonate - Bridgit XC	6300	9500		3/8"
Cellulose - Coarse	45	2000	354	10
Cellulose - Fine	2	353	70	40

TABLE 4
Bridging Material Section Chart

	$CaCO_3$	Resin	Salt	Cellulose
Gas Well	YES	NO	YES	NO *
Oil Well	YES	YES	YES	YES
Sandstone	YES	YES	YES	YES
Carbonate	YES	YES	YES	YES
Acid Soluble	YES	NO	NO	PARTLY
Water Soluble	NO	NO	YES	NO
Oil Soluble	NO	YES	NO	NO
Enzyme Cleanup	NO	NO	NO	YES
Water-base Carrier	YES	YES	YES	YES
Oil-base Carrier	YES	NO	YES	YES

* unless fairly prolific drawdown is available

Figure 1
Design Process

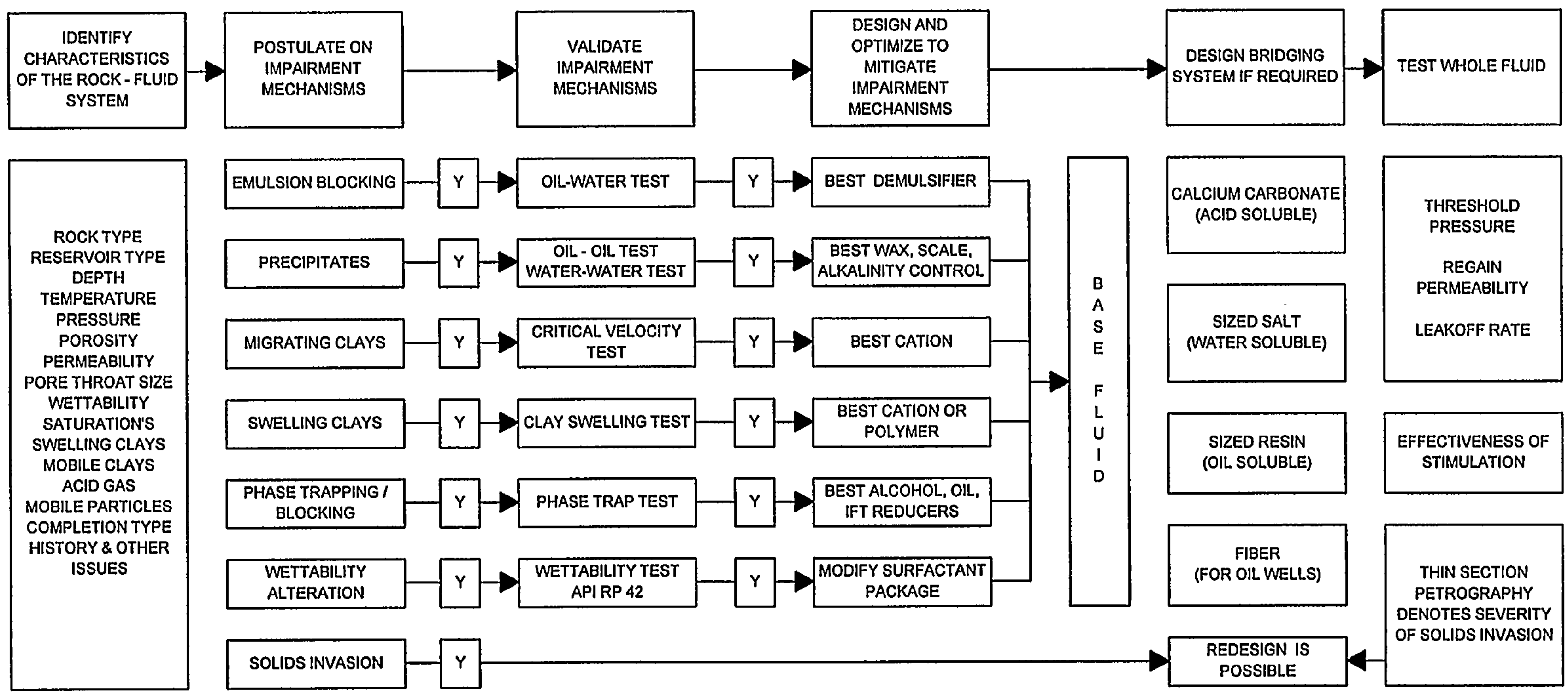

FIGURE 2
TYPICAL PERMEABILITY-POROSITY CROSSPLOT

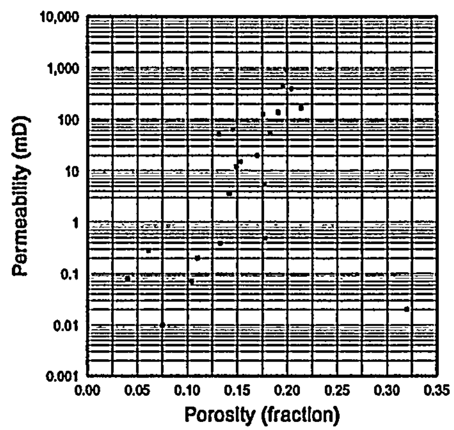

FIGURE 3
TYPICAL PORE THROAT SIZE DISTRIBUTION

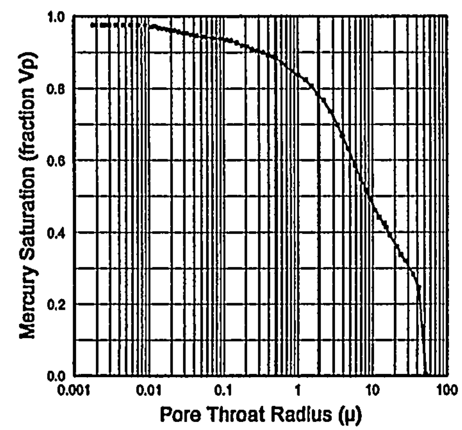

FIGURE 4
TYPICAL WETTABILITY TEST PROFILE
(Oil-Wet Core)

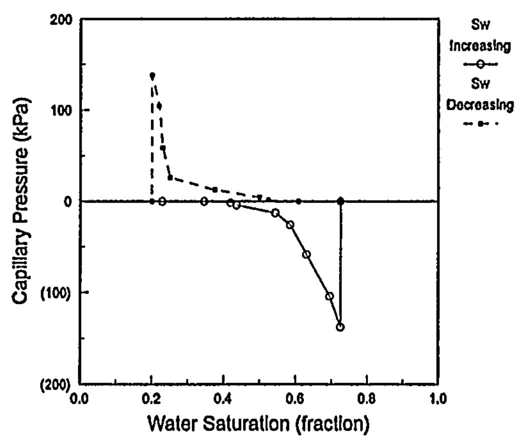

FIGURE 5
TYPICAL WATER ANALYSIS

Ion	ppm
Na	39,600.0
K	225.0
Ca	1,245.0
Mg	647.0
Ba	2.3
Sr	1.8
Fe	2.2
Cl	64,439.0
HCO3	220.0
SO4	1,100.0
CO3	23.0

FIGURE 6
TYPICAL XRD ANALYSIS

SAMPLE	BULK ANALYSIS													
	QTZ	PLAG	KSPAR	PYR	CALC	DOL	ANK	SID	BARITE	KAOL	ILL	CHL	ML	SM
1	92	--	--	4.0	Tr	0.5	1.0	--	--	1.5	0.5	0.5	--	--
2	97.5	--	0.5	1.0	--	--	--	--	--	0.6	0.6	--	--	--
3	96.6	0.5	--	1.5	--	--	--	--	--	1.0	0.6	Tr	--	--

SAMPLE	GLYCOLATED CLAY FRACTIONS				
	KAOL	ILL	CHL	ML	SM
1	92	Tr	1.0	1.5	--
2	97.5	--	--	0.6	--
3	96.5	--	--	1.0	--

FIGURE 7A
LONGITUDINAL MRI

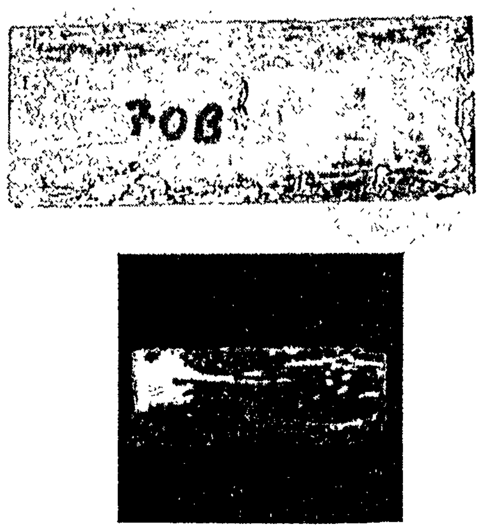

FIGURE 7B
LATERAL MRI SECTION SLICES

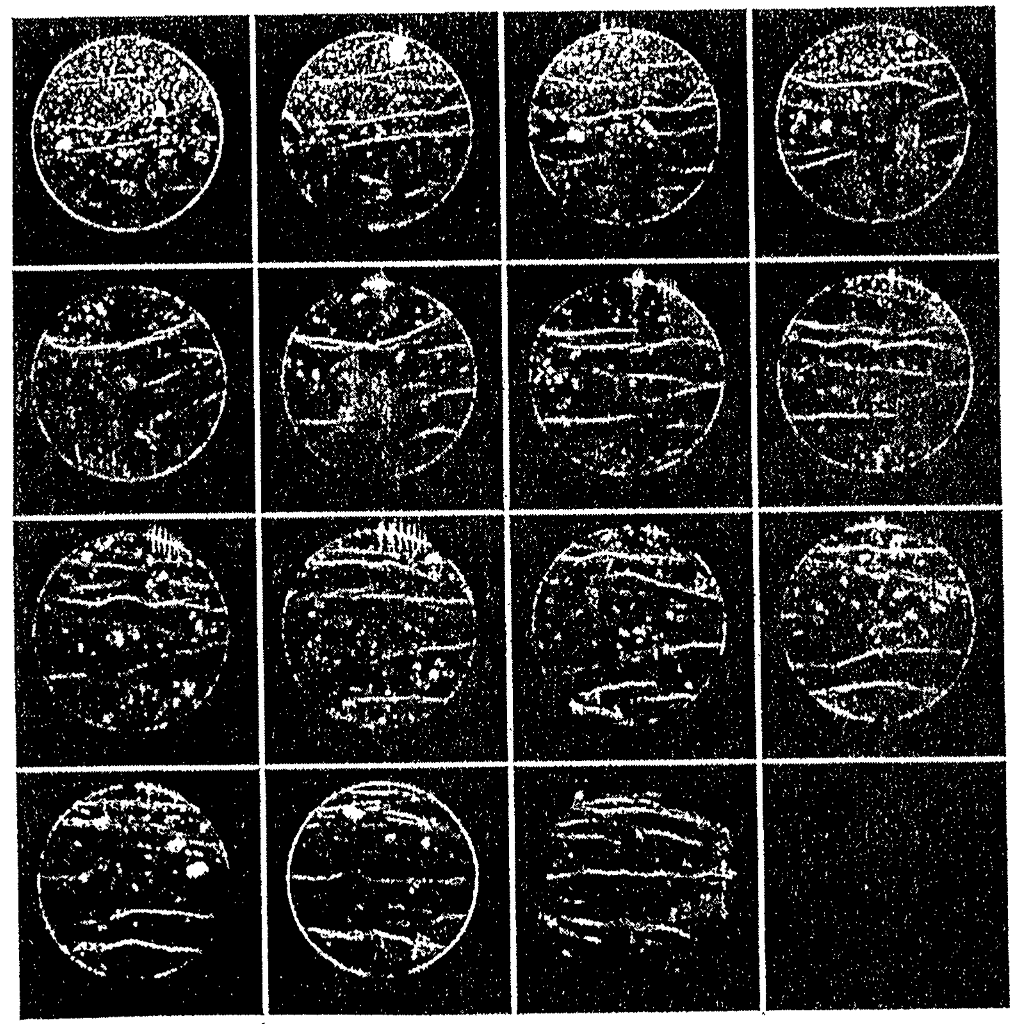

FIGURE 8
TYPICAL OIL-OIL COMPATIBILITY TEST DATA

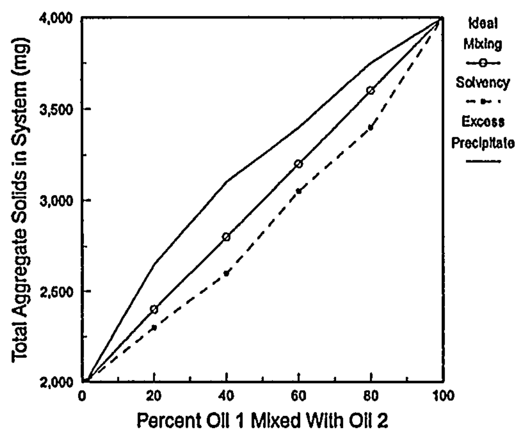

FIGURE 9
TYPICAL CRITICAL VELOCITY TEST

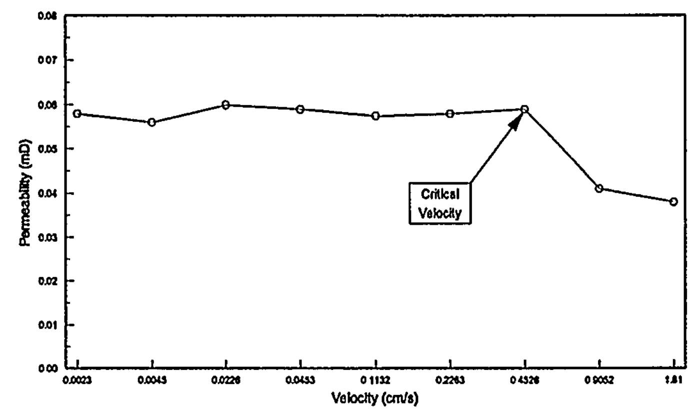

FIGURE 10
TYPICAL FRESH WATER SENSITIVITY (Clay Swelling) TEST

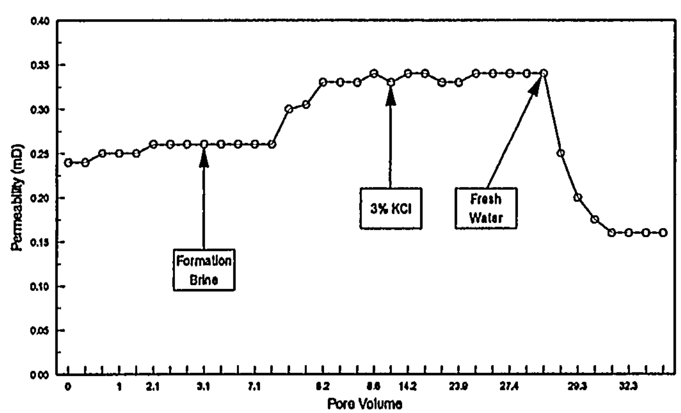

FIGURE 11
TYPICAL PHASE TRAP TEST RESULTS

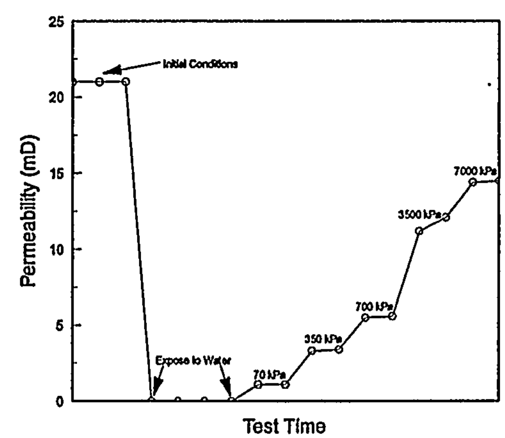

FIGURE 12
DISTRIBUTION CURVE COMPARISON

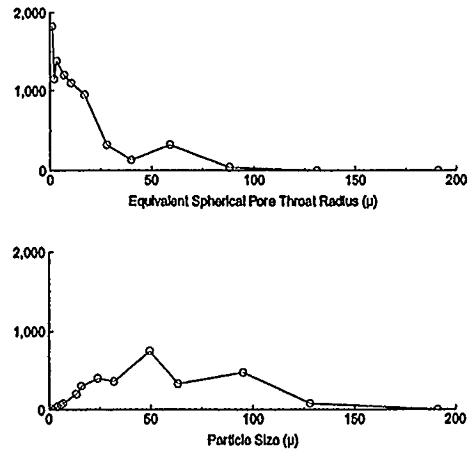

FIGURE 13
TYPICAL REGAIN PERMEABILITY TEST APPARATUS

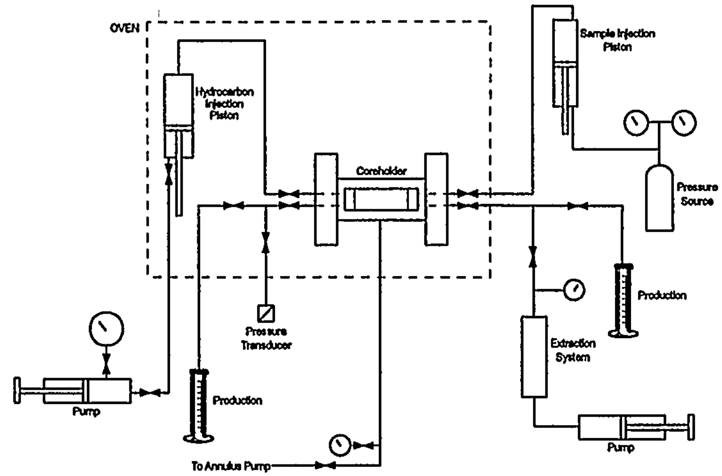

FIGURE 14
TYPICAL REGAIN PERMEABILITY TEST

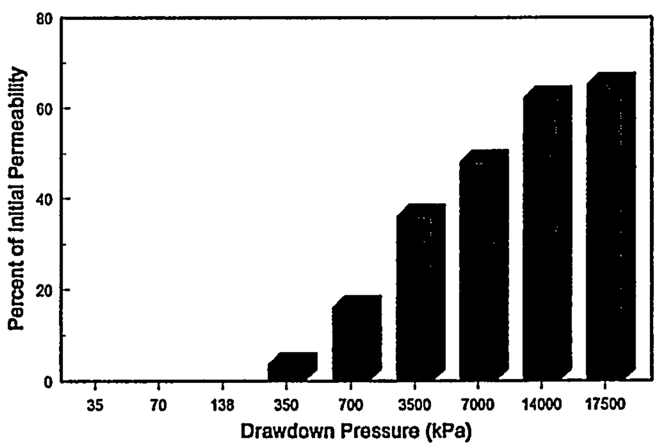

FIGURE 15
TYPICAL FLUID LEAKOFF PROFILES