AADE-08-DF-HO-05

Drill-in fluid design, getting it right from the start!

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Abstract

The ever increasing cost and the difficult challenge in the search for oil and gas reserves emphasizes the need for engineered success in all aspects of well design. The industry has a perception that one of the easiest ways of negating the success is a failure by drilling fluids engineers to provide solutions that result in highly productive wells. In other words, “it’s the mud’s fault” when a well doesn’t reach the expected production rates. This paper does not deny that in some cases, this could be a correct assumption, but it does demonstrate the process and methodology that can be applied to prevent the fluid and well engineers from getting into this position.

The simplest way of preventing formation damage in a well is to not drill into the reservoir. Obviously, this is impossible if we are to produce oil or gas. We also must try and reduce the damage caused to the lowest practical level. It can be very difficult to reduce the damage to zero, but it can be significantly lowered by following simple principles that are described within this paper. In some cases, if damage is proving resolute, or the well cannot be cleaned up by using its inherent pressures and flow characteristics, we can remove damage by post drilling treatments whose efficiency is clearly measurable.

The more complete the reservoir description is, the easier it is to create a fluid design with a much lower risk of formation damage, and the verification testing will be more representative of actual downhole conditions. If certain important parameters and conditions are not known, this paper will discuss how we can measure, estimate and simulate them. This paper will describe the equipment that is now available to accurately determine pore throat sizes, measure permeability, analyze mineralogy and ion content of formation and reservoir fluids, accurately quantify drill-in completion fluids or post-treatment performance, and help to provide assured high productivity.

Introduction

To ensure high well productivity, a complete and thorough study must be undertaken and a formulation engineered that will provide the lowest possible effect on formation and completion permeability. This paper will present a methodology that will review the downhole conditions that can effect a reservoir drill-in fluid’s (RDIF) design and also present how the engineer can make assumptions if all the information is not available when designing a RDIF. A range of sophisticated equipment is required to analyze the reservoir and also to measure the fluids performance with regard to well productivity. The paper will describe this equipment and explain how it can be utilized to minimize the fluids effect on reservoir’s physical and chemical make up. This can be finally verified on samples of reservoir core in a dynamic permeameter, if no reservoir core is available then artificial core that closely matches the reservoir description can be utilized.

Definition of a reservoir drill in fluid (RDIF)

A generally accepted definition of a RDIF is difficult to find but most would agree that a RDIF is a fluid that enables a well to be drilled and causes a minimum amount of damage to a reservoir, allowing production to be maximized. Therefore a RDIF will have the attributes of both a drilling and a completion fluid. Many within the industry insist that only acid soluble components may be included in a RDIF formulation. However, if no acid treatment is planned, or proven to be required, products that are non-acid soluble may also be successfully included, especially if they enhance the fluid’s performance with regard to drilling performance or well productivity.

Both aqueous- (WBM) and invert emulsion-based fluids (OBM) can be RDIFs. There has been some debate within the industry as to which fluid type (WBM or OBM) has the lowest damage potential, but it can be very foolish to generalize and make such rigid assumptions. Each system has advantages and disadvantages and their potential application in a reservoir should only be decided upon when all the relevant information has been correlated. A decision should not be made on preconceived ideas based on past successful applications within the well engineer’s experience. Care must be taken when comparisons are made between wells with potentially dissimilar physical and chemical characteristic or different completion types.

When formulating an aqueous fluid (WBM), a base brine is selected with a density that will reduce solids content to a minimum. The solids utilized to impart bridging and some density are usually Calcium Carbonate, which are acid soluble. Viscosity and fluid loss control are provided by polymers that are also acid soluble. WBM filter cakes can be effectively removed by a combination of enzyme and acid post treatments (Singh et al[1]).

An invert emulsion fluid (OBM) generally requires a higher solids loading, as high density brine can only be used as part of the water-based internal phase.. In the past, OBM filter cakes have been more difficult to remediate so the requirement for acid soluble components has not been great. With the introduction of micro-emulsion clean-up technology (Lavoix et al[2]), this is no longer the case and the demand for acid soluble OBM filter cakes is increasing. This can result in a requirement for a more thorough procedure when selecting OBM chemical components to maximize the efficient removal by micro-emulsion/acid post treatments. Independently of whether the fluid is aqueous or oil based, it has been found that complete dissolving of the filter cake is not always required and only partial removal of filter cake components or disruption of the cake's integrity is required to give very high well productivity. This disruption is often created by decreasing the hydrostatic pressure so the wellbore pressure is lower than reservoir pressure, in a large number of cases this is all that is required, but this is not always the case. Completion type, such as an open-hole injector may need a post treatment as an essential part of the well program. Laboratory testing will confirm if a post treatment is required on any type of open-hole completion.

Basically if an acid-based post treatment is required then acid soluble components should be used. This does not completely rule out the inclusion of non-acid soluble chemicals, especially if they are proven not to have a negative effect on production. If no acid-based post treatment is planned or required, then there is no reason why non-acid soluble components such as Barite or Graphite cannot be used. In fact, some of these so called non-desirable products can have large benefits to the fluids performance, in particular Graphite, which is very inert but excellent at wellbore strengthening (Ashton et al[3], Vickers et al[4]).

Another common misconception within the industry is the aversion to including "black powders" in RDIFs. These chemicals are usually applied as filtrate controllers and have the reputation of being very damaging. Black powders are usually asphaltic compounds and produce very low filtrate invasion rates which can reduce the amount and depth of damage. Whether "black powders" are damaging is debatable, and should be reviewed on a case by case basis. The advantages that the addition of asphaltic filtration controllers can sometimes give should override preconceived ideas that they are always damaging, and should not be completely excluded from RDIF design.

Clays are used in both aqueous and oil-based drilling fluids to provide viscosity and help to build filter cakes. Their inclusion in RDIF formulation should be minimized and if possible completely avoided, especially in the case of WBM. Some organophillic clays can be used when designing invert emulsion RDIFs as their presence in the oil-wet state does not provide a damage mechanism, but the same cannot be said for water-wet clays in WBMs. The hydrating of clays in RDIFs should be avoided at all costs and minimizing their concentration or eliminating them completely must always be a priority.

In conclusion, we can say that a RDIF may contain any product that will not drastically reduce reservoir permeability. Whether a chemical is damaging or not should be verified in laboratory tests, as the damage mechanism is often dependant upon the reservoir characteristics. Just because a chemical has shown to be damaging in one reservoir does not mean it will be always responsible for lowering permeability in every case.

Formulation Process

The first step in the formulation process is to analyze the geological make up of the reservoir. Samples from the reservoir are nearly always available, but not always in great quantity. As fluid design is such a critical aspect of the entire well design, it should be argued that fluid engineers should give high priority to this valuable resource. It will make the whole process more meaningful if actual reservoir and cap rock core samples are made available. If the Reservoir Engineers cannot spare any core, then some maybe obtained after they have performed their testing. If no core is available, then cuttings must be obtained.

Geological Analysis

Actual rock samples from the reservoir, (cuttings or core) will undergo X-ray Diffraction (XRD) (**Figure 1)** and Scanning Electron (SEM) (**Figure 2)** analysis. This will enable us to accurately describe the mineralogy and how it can effect the fluids composition. A rock sample is dried in an oven, ground with a mill grinder, and sieved to get particles of less than 50 microns. Part of this sample is run for quantitative X-ray analysis of quartz, feldspars and other non-clay minerals. Another part of the ground sample is dispersed in a column of distilled water. The small suspended particles from the upper layer in the water column are then collected and placed on a glass slide and exposed to X-rays to analyze for clay minerals. Another two samples of these small clay particles are saturated with monoethylene glycol, one of which is heated to 300^{o}C. All three samples undergo XRD and the plots are evaluated and quantified for Smectite, Illite, Kaolinite and Chlorite clays. By comparing the difference in the three plots, the potential of the clay to experience swelling can be estimated (**Figure 3)**. It is difficult to generalize with regard to this type of analysis and correct interpretation requires a high level of experience and skill from the operator. It can be assumed that if the overall breakdown of this rock sample shows less than 20% Illite/Smectite, then hole stabilization might not be an issue and a WBM could be used to drill this formation. Other assumptions can also be made with regard the potential brine type that is best suited to inhibit the clay from swelling. As a fluids provider, Baker Hughes Drilling Fluids has a large database of clays from wells drilled throughout the world. This is scanned for clays with similar compositions, and the clay under investigation can be potentially matched with similar clays for suggested successful inhibition mechanisms that have been used previously on other clays with matching XRD/geological analysis.

Shale samples from cap or interbeded formations can be analyzed for their hydration capacity and may be tested by physically measuring their swelling capacity on a Linear Swellometer. This in conjunction with Cation Exchange Capacity (CEC) and XRD data will enable us to accurately asses whether WBM can be used. CEC is a standard mud laboratory test and is a simple method of measuring the amount of reactive shale in a sample. A solution is made up with the rock and increasing amounts of dye are added. By paper chromatography, the volume of dye absorbed by the clay can be calculated and reported as a number. Clays and their reactivity can be described using this number. Other shale evaluation techniques include Capillary Suction Time (CST), cuttings dispersion, and more sophisticated triaxial and drilling simulation apparatus.

Reservoirs are normally sandstone or limestone capped with an impervious clay cap rock. Although reservoir rocks are normally inert, they do contain varying amounts of clay and other minerals that can change in physical structure. The shales that are present in the reservoir should also be tested for compatibility with the completion brines. These brines should be selected to not only to allow low deformation of clays in the wellbore, but also interstitially so as not to change the physical conditions in pore spaces. The clays in the wellbore must be stabilized to allow the running of screens and gravel packs as well as liners to programmed depths. Losing well productivity due to completions not being run to the required depths is a common problem and one of the main reasons that OBMs are used in reservoirs.

General fluid properties

Although it is of the utmost importance that the fluid has the lowest possible impact on the productivity of the well, it must never be forgotten that the fluid has to provide a trouble-free drilling phase in the well's operation. Fluid density, hole cleaning efficiency, filtrate control, and well hydraulics must all be optimized to agreed parameters. As a general rule, to reduce formation damage it might be advisable to reduce the RDIFs overall solids loading to the lowest practical concentration.

Density of drilling fluids is normally obtained by the addition of solids, which is typically Barite due to its high specific gravity. Barite as an addition to a RDIF formulation is usually avoided as it is non-acid soluble, but as discussed earlier, this does not mean that it will always cause formation damage. Whether Barite can be used will probably depend upon the pore throat sizes that are present in the reservoir. If the pore throats are large, then the Barite particles may invade deeply and then become very difficult to remove, causing irreversible damage. Calcium Carbonate can also be used to provide density, but as its specific gravity is considerably lower than Barite, almost twice as much is required to give the similar density effect. Fluids that use Calcium Carbonate to provide high densities can have poor rheological profiles with high plastic viscosities due to high solids loading. Some fluid systems which utilize high concentrations of Calcium Carbonate use micronized grades so the weighting agent almost becomes self suspending. This reduces the required polymer content, but the micron-sized particles can result in deep invasion and increase the risk of damage. Barite can also be micronized and used as a weighting agent as can Manganese Tetraoxide which has a sub-micron particle size. The ability of these weighting agents to be benign with regard to formation damage should always be verified before allowing them into contact with reservoirs in RDIF's. Using appropriately sized bridging particles of Calcium Carbonate in conjunction with non-acid soluble but dense materials such as Barite is the usual compromise. This mixture of solids can provide good bridging characteristics along with low solids loading of the RDIF.

In aqueous fluids, viscosity and fluid loss are normally provided by polymers. Non-ionic polymers are preferred as they will have the least interaction with the rock being drilled and are usually fully compatible with most commonly chosen brines. Low molecular weight polymers are also preferred, as high molecular species have often been shown to induce formation damage as they are difficult to remove out of pore spaces.

Viscosity is an essential aspect of any drilling fluid design. It is imperative that drill cuttings are removed efficiently from the wellbore and the gel strength must be high enough to suspend cuttings when the rig pumps are turned off. To provide this in aqueous fluids, the preferred polymer is usually Xanthan Gum (1-2 ppb concentration). Other polymers exist than can produce good rheological profiles. Polysaccharides and Hydroxyethyl Cellulose have been successfully used, but Xanthan proves to be the most versatile and commonly used. In aqueous RDIFs, the use of clays should always be avoided as the risk of damage is very high if clays are present. Gel structure and viscosity at low shear rates can also be difficult to obtain but often a synergy effect is created when a filtration control polymer is added. The filtration control polymers not only reduce fluid loss but also provide some viscosity to the RDIF. This is probably true for both OBM and WBM. The usual method of viscosifing OBMs is to use organophillic clays. The concentration of these in RDIFs should be kept to a minimum as their potential to block pore throats in the reservoir is high and has been known about for a considerable time (Glenn et Slusser[5]). Liquid polymeric viscosifiers that work in base oils are available, but care should be taken with these. If any oil filtrate enters the formation it will be more difficult to remove if it is viscosifed with liquid polymers.

Filtration control is vital to the success of the RDIF performance. The relationship between fluid loss and formation damage is mainly linear (Glenn et Slusser[5]). The greater the ingress of filtrate into the formation, the higher the damage will be. Fluid loss should be tightly controlled and in particular there should be a focus on minimizing spurt loss

(Kruegger[6]). This is the sudden loss of solids-laden fluid into the formation prior to and during initial filter cake formation (**Figure 4)**. This has been shown to correlate strongly with near wellbore damage (Navarrete et al[7]).

Extensive research looking at the behavior of different filtration controllers has found that starches are the best for this purpose in RDIFs (6-8 ppb). Other fluid loss controllers can be more efficient at reducing fluid loss, but starches have repeatedly proven to be less damaging and easier to remove either by backflow or enzyme/acid post treatment. When starches are used, a biocide should also be added to prevent bacterial degradation of the polymer and the growth of biomass, which in itself can be a damage mechanism. Asphaltic materials are mainly used for invert emulsions but can also be soluble in aqueous fluid so they can be used to control fluid loss in both (1-5 ppb). Lignites are also used in OBMs and have proved to have low risk when considering their effect on reservoir permeability. Some OBM formulations do not use any direct filtration controllers and rely on the emulsion to keep fluid loss low by preventing fluid passage through the filter cake (concentration of approx 8-14 ppb). This can have advantages if the fluid loss additives prove to effect permeability, but care must also be taken with emulsifier strength and concentration. If an excess of emulsifier is present in an OBM RDIF when it enters the formation in the filtrate, it can come into contact with the connate water in the reservoir. This can result in blocking emulsions being formed. This is one of the most common damage mechanism when using OBMs in the reservoir.

Specialty chemicals may also be required to assist in the drilling process. Clay stabilizers are often utilized as reservoirs are rarely all sand or all limestone. The cap rock will usually be a clay. Clay interbeds or interstitial clay may also need stabilizing. In the case of invert emulsions this is relatively easy and should not represent any appreciable risk. If a WBM is used and a large clay fraction is present in the reservoir then the easiest way inhibition the hydration of those clays will be using a base brine that has the smallest effect on clay swelling. Other additives such as Glycols and Amphoteric Surfactants can also be used to control clay hydration in WBMs (approx 3% required by volume). Glycols also have the added benefit of producing thin and lubricous filter cakes. They can also lower fluid loss and do not seem to have a great effect on well permeability. Greater care needs to be taken with surfactants as changes to surface chemistry might not always be positive with regard to well productivity.

When formulating any RDIF, all additive concentration should be kept to a minimum. Every addition has an effect on fluid properties and keeping those effects down to the minimum requirements is a good general philosophy. The addition of a chemical rarely has only one effect and any secondary results may not be desirable. In other words, we can cure one problem but create another.

Pore Throat profile and Bridging

A critical part of the RDIF design is the bridging selection. Calcium Carbonate is the most commonly used bridging agent as it is easily ground into different particle sizes **(Figure 5)**, readily acid soluble and cost effective. The bridging selection process needs samples from the reservoir. Using those samples, the permeability and the dimensions of the pore spaces can be measured.

The pore throat dimensions are required to accurately predict the sizes of the bridging materials that will be used in the DIF for all the completion types. If no pore throat data or core is available, than an average pore throat size can be estimated by taking the square root of the permeability. This method cannot be relied upon to be accurate but gives a good approximation.

If reservoir material is available, a mercury porosimeter (**Figure 6)** is used to measure pore throat sizes. Mercury is injected into a reservoir sample at a given flow rate. Tthe changes in pressure as the mercury flows through varying sized voids is measured and recorded. That data can be put into a software package and an accurate description of the pore throat size distribution is created (**Figure 7**). This information can then be inputted into other software **(Figure 8)** that will predict the size distribution of ground Calcium Carbonate required to form the most efficient bridge in the reservoir pore spaces (Jones et al[8]). The different sizes and blends of Calcium Carbonate are then added to the other components of the RDIF to give a finished formulation ready for testing.

A thin, tough filter cake with low lift capabilities is the goal (Kruegger[6]) and the fluids ability to form such a cake is tested on Aloxite discs of the same pore throat sizes as the reservoir. Once the efficiency of the cake is verified, the fluid can be tested on a Sand Pack Permeameter **(Figure 9)**. This apparatus will measure the fluids lift off pressure and its damage potential on an Aloxite disc, and in the case of a screen completion, it will measure the pressure required to pass the filter cake through screen coupons. This process is more or less identical for both WBM and OBM RDIFs. OBMs require a smaller concentration of bridging material than WBMs to form an efficient cake. WBMs required a bridging concentration of approximately 40-50 ppb and OBMs can form a good bridge with a lower concentration of 20-30 ppb. These concentrations are only guides and optimum levels should be verified by doing numerous tests with varying concentration. A little excess can be advisable as some bridging can be stripped out when the mud is initially circulated over the shakers. The action of rotating drill pipe in casing can also cause attrition and change the particle size distribution of the bridging material. This has been studied on various projects and not seen as a large problem and can be adequately managed by continually replenishing the larger particle sizes with new bridging material of a similar large size as the rig drills ahead.

Fluid Compatibly Testing

Formation water samples should be collected and used to test compatibility with the proposed well fluids. Formation water investigation can be done using ion analysis. Large volumes of simulated samples of the reservoir brine can then be made up and used in laboratory tests. Testing of brines is probably the most critical, but all fluids that come in contact with formation fluids during the project should tested for any possible incompatibility. This is to prevent problems arising such as salt precipitation or the creation of blocking micro-emulsions. The compatibility testing can be done by combining the well fluids in 250 ml Duran bottles in different ratios in order to give a range of results of increasing/decreasing concentrations. The range in the bottles can be observed for any incompatibility. The whole range of mixes should then be aged statically at the BHT for 24 hours and observed again for any incompatibility. If the BHT is above 95° C, then a pressurized vessel will be required to avoid expansion and boiling hazards. Photographs can be taken before and after aging and observations recorded (**Figure 10).** Brine types and concentration may have to change if precipitation is observed. Damaging emulsions can be prevented by the addition of surfactants (Quintero et al[9], Dalmazzone at al[10]) at small concentrations (1% by vol).

Return Permeability Testing

The sandpack permeametry apparatus **(Figure 9)** creates a simplified downhole simulation in which permeability of an aloxite disc can be measured before and after exposure to the RDIF. This gives an idea of potential damage caused by the RDIF. The advantage of sandpack permeametry over the more accurate Hassler cell permeametry is the ease and length of time a test can be completed in. Sandpack permeametry should be used as a screening process to test several fluids over a short time scale before stepping up to Hassler cell permeametry.

The permeability and pore throat of the reservoir is simulated with the appropriate sized aloxite disc which then has reservoir sand packed on top of it. The reservoir sand is held in place by gravel and mesh. Base oil is pumped at a steady flow rate upwards through the sand and aloxite disc, monitoring the pressure in order to find the initial permeability. The RDIF is then pressed against the aloxite disc at the desired overbalance pressure and reservoir temperature. After this stage, the excess RDIF is removed and replaced with base oil, with care being taken not to disturb the filter cake. The flow of base oil is then restarted in the production direction with lift of pressure and final permeability being recorded.

Hassler cell permeability picks up where sandpack permeability finishes **(Figure 11, 12)**. Hassler cell permeametry (HCP) allows the simulation of downhole reservoir conditions to a high degree. HCP can use actual reservoir core material, formation water, and production crude, all with the aim of closely simulating the reservoir conditions. If actual reservoir core is not available then core with similar permeability can be substituted. Formation water can be simulated if a make up formulation is available or again estimated using formulations from similar wells. Production crude can be used in return peremeametery studies but can be difficult to store and handle. At low temperatures, waxes and asphaltenes form in crude and these will cause anomalies in pressure readings when attempts are made to flow through core samples. A standard mineral oil is normally utilized to overcome these issues.

Once the downhole conditions have been given to the permeameter operator, a full sequence testing of all the fluids and exposure times can also be achieved at downhole pressures and temperature (Marshal et al[11]). A standard Hassler cell return permeability measurement would involve first cleaning the core and preparing to irreducible water saturation with formation brine. Then an initial permeability would be taken by flowing oil through the core. The next stage is to apply the RDIF to the face of the core both dynamically and statically for an allotted time to simulate the reservoirs exposure to the RDIF while drilling. The “mudding off” is then followed by the same sequence of fluids that will be exposed to the core. At this point, the core should be exposed to any displacement fluid that is used in the completion operation as well as any post treatment that is intended to be used. Preferred efficient post treatments for an aqueous RDIF would be an enzyme breaker fluid and for an oil-based RDIF would be a single phase micro-emulsion (SPME) fluid. It is also possible to simulate screen or gravel pack completions using sophisticated permeametry equipment. After the end of the fluid exposure sequences, a simulated draw down is carried out to identify the pressure at which the filter cake lifts off and the well will begin to flow. The final stage is to take a final permeability measurement by again flowing oil through the core. This final value is then compared against the initial permeability to get a measure of retained permeability and a quantification of damage done **(Figure 13)**.

It is possible to carry out additional permeability measurements after the final permeability to try and identify the damage mechanisms. Offloading the core and manually removing any remaining filter cake before repeating the permeability stage can indicate whether the damage is internal (inside the core) or external (caused by the filter cake). It is also possible to offload and trim the core to simulate fracturing and also to identify if the damage is in the nearbore area or if the damage is deeper in the reservoir. A Scanning Electron Microscope (SEM) can be utilized to try and identify damage mechanism deep within the rock pores. Once the damage mechanism has been identified, the RDIF formulation can be changed to try and improve on its performance. Further tests on the reformulated RDIF using the same procedure will be required to verify that the changes have produced a positive result.

Enzyme Breaker Fluid for WBM

When maximum productivity is required from a reservoir it is possible to increase PI by treating the well with an enzyme breaker fluid (Harris et al[12]). This fluid contains active components, enzymes (up to 1% by vol) to break down both

Xanthan and Starch, and an acid generator chemical (up to 10%) to dissolve calcium carbonate in the filter cake. The acid generator reaction, converting an ester into acetic acid can be driven by chemical, enzyme, or salt selection. This fluid can be used as a post treatment or can be used as the carrier fluid for a gravel pack.

The breaker design screening is carried out using a standard double-ended HTHP cell. The RDIF is used to build a filter cake on an aloxite disc at the BHT with an appropriate overbalance pressure. The excess mud is then removed and replaced with the enzyme breaker fluid. Care has to be taken not to disturb the filter cake as the breakthrough time has to be recorded. The filter cake is exposed to the enzyme breaker formulation and left to soak for the required time period. The fluid loss is monitored over time, and after the required time period, the filter cake is removed and photographed **(Figure 14)**. Total breakdown of the filter cake is targeted, however a time delay is seen as desirable to allow time for lower completion work to be accomplished before experiencing losses.

Mesophase remediation treatments for OBM

There are a number of post treatments available to remove OBM filter cakes, but recent technological advances in the field of surfactant technology have produced very efficient remediation systems using mesophase technology. These blends of surfactants form microemulsions when they come in contact with oil. If they are applied to an OBM filter cake, the oil-wet solids become water-wet and the emulsion is broken down to a micron-sized droplet **(Figure 15)**. The breakdown of the emulsion causes the integrity of the filter cake to disintegrate. The water-wet solids are easily acidized with Acetic or Formic Acid. A time delay mechanism can be included in the formulation to ensure an even treatment is made.

Conclusions

The most important conclusion to be made is that the drilling engineer must be prepared to gather as much well data as possible. If the data has not been created, the fluids provider or specialist laboratories should be able to find the information required if reservoir core and liquid samples are available. If no data or core is available, estimations can be made and artificial materials with similar properties to the reservoir can be utilized for testing against proposed formulations. When the fluids supplier has all the relevant data and performs the correct sequence of tests, the risk of formation damage and loss of productivity can be severely reduced. The permeameter is probably the most important tool the mud engineer has when designing and verifying fluid and component suitability (Van der Zwagg et al[13]). A proactive approach is always more efficient in terms of cost, time, and productivity when designing a fluid to be non-damaging in the reservoir.

The key points in designing a RDIF are:

1. The fluid properties must allow the well to be drilled efficiently and safely.
2. Suitability of all chemical components must be verified as non-damaging in the formulation.
3. Clays should be avoided in WBMs, and minimized in OBMs.
4. All product concentrations should be kept to a minimum.
5. Do not rule out using non-acid soluble products, especially if no post treatment is required.
6. Filter cake quality and minimizing depth of invasion is critical.
7. Bridging size selection and concentration must be investigated.
8. If damage is irreversible by back flow, it can be successfully removed by post treatments in both WBM and OBM applications.
9. Occasionally, only partial disruption of the filter cake integrity is required to enable high well production.

Acknowledgments

The authors wish to thank the BHDF Technology Group for their support and permission to publish this paper and the help and advice given by many members of the SPE and the industry in developing a large experience and knowledge base on this subject which the authors could draw upon.

Nomenclature

RDIF	=	*Reservoir Drill In Fluid*
SEM	=	*Scanning Electron Microscope*
XRD	=	*X-Ray Diffraction*
OBM	=	*Oil-Based Mud*
WBM	=	*Water-Based Mud*
HTHP	=	*High Temperature High Pressure*
HCP	=	*Hassler Cell Permeametry*
BHT	=	*Bottom Hole Temperature*
PPB	=	*Pounds Per Barrel*

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Fig. 1—An X-Ray Diffraction (XRD) unit is used to examine core samples and cuttings.

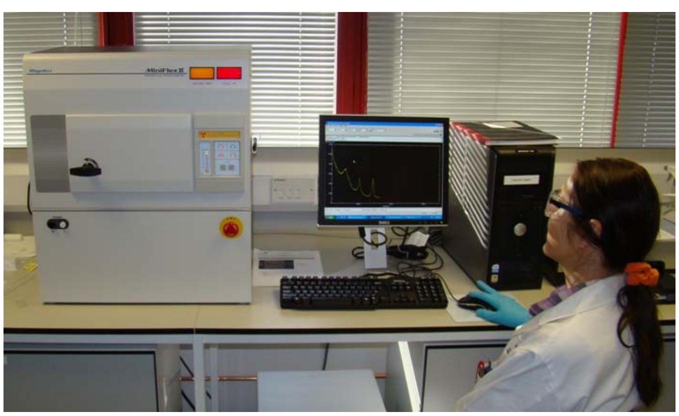


Fig. 2—A Scanning Electron Microscope SEM, also used for core and cuttings evaluation.

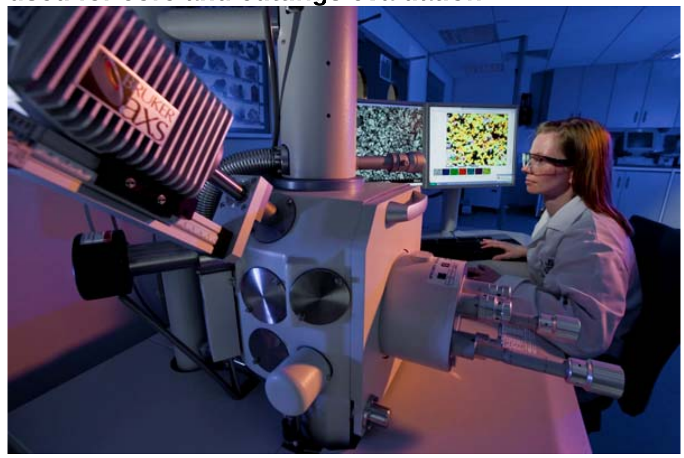


Fig. 3—XRD spectra shows glycolation effect.

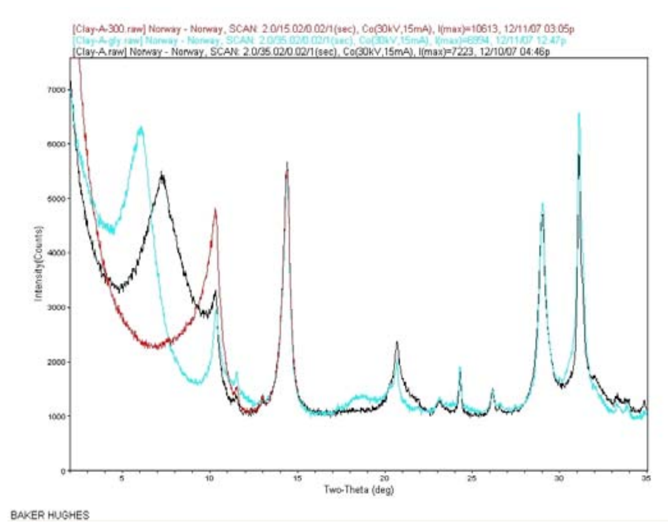


Fig. 4—Cross section of a correctly formulated RDIF filter cake showing low invasion on an aloxite disc.

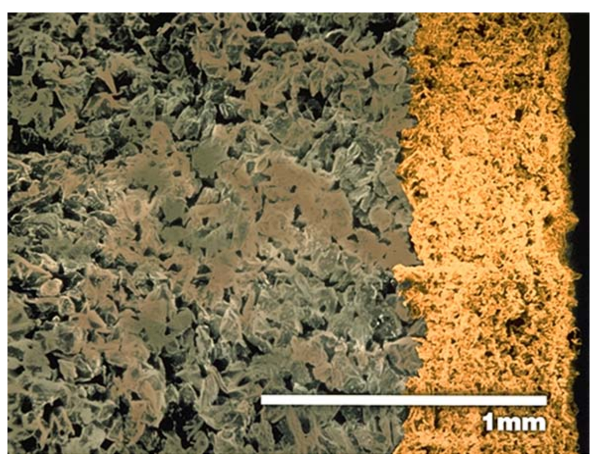


Fig. 5—Sized Calcium Carbonate viewed with an SEM.

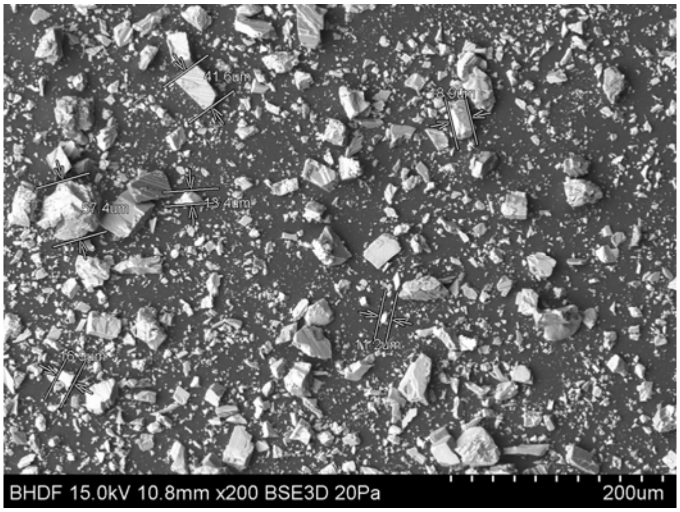


Fig. 6—A porisometer is used to measure pore throat sizes.

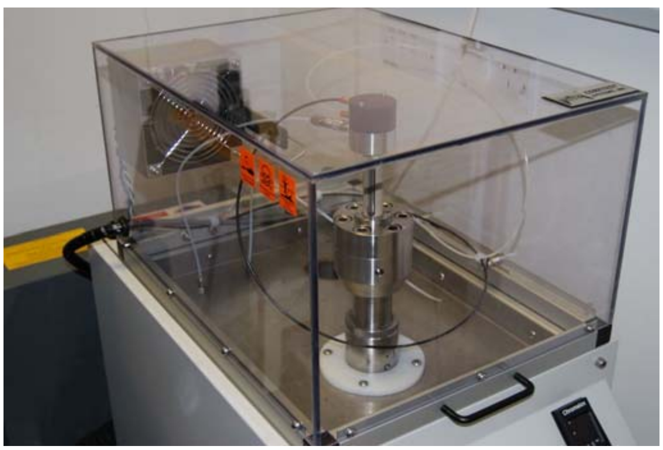


Fig.7—Porisometer data showing distribution of pore throats in a core sample.

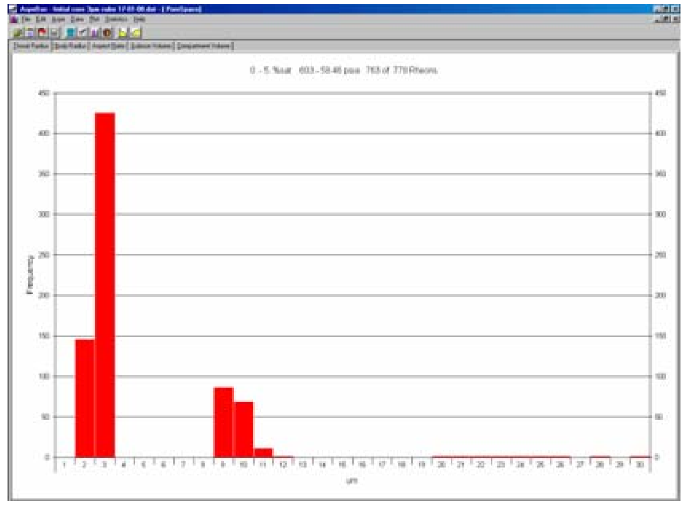
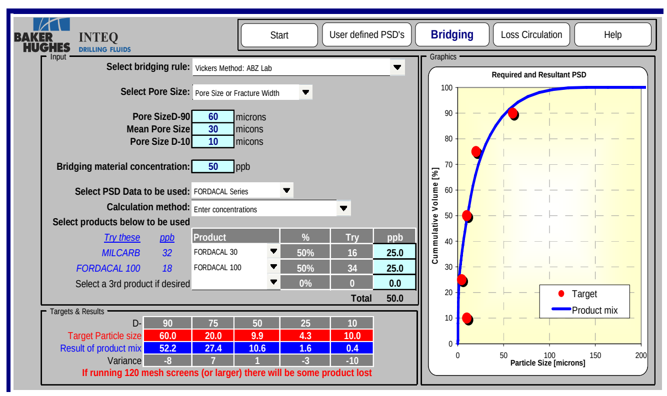


Fig. 8—In-house Bridging selection software provides an accurate description of the pore throat size distribution.



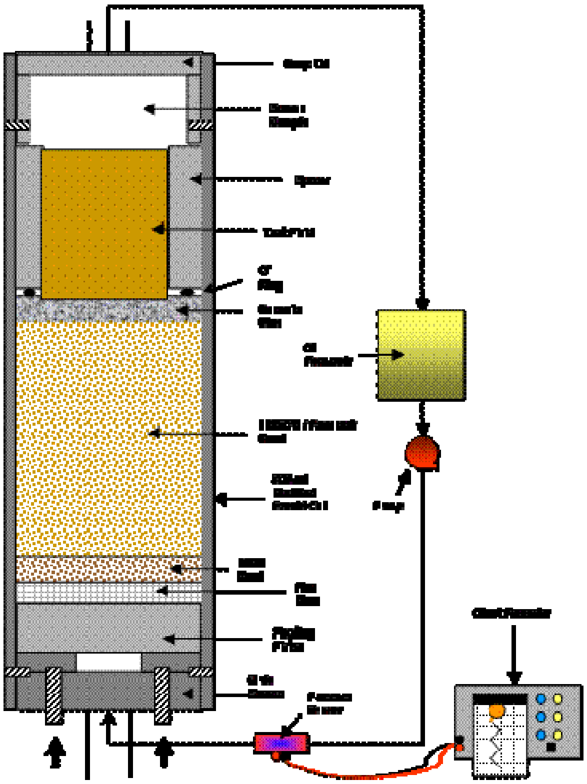


Fig. 9—A Sandpack Permeameter measures the fluids lift off pressure and its damage potential on an Aloxite disc.

Fig. 10—Compatibility Testing Before and After Aging.

Fig. 11—A Hassler cell in the permeameter.

Fig. 12—Schematic of Hassler Cell Permeameter.

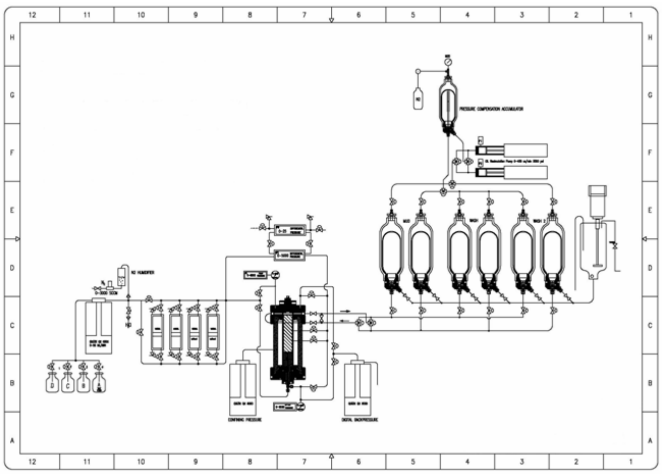


Fig. 13—Return Permeability Graph.

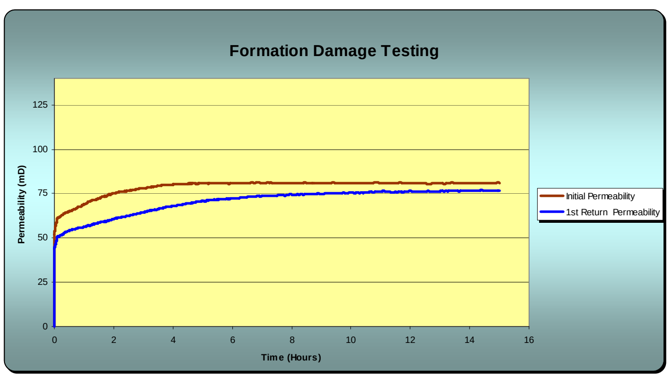


Fig. 14—Filter Cake Destruction by Enzyme Breaker Fluid.

A. Before Treatment B. After treatment

Fig. 15—Filter Cake Destruction by Single Phase Micro-Emulsion.

A. Before Treatment B. After treatment