



Associative Polymers for Invasion Control in Water- and Oil-based Muds and in Cementing Spacers: Laboratory and Field Case Histories

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Abstract

Fluid invasion during drilling and completion operations causes many of the biggest problems faced in well construction. In the payzone, invasion can produce formation damage as well as affect the quality of log information and fluid samples. It can also give rise to differential sticking and promote lost circulation of mud and cement. All these problems become worse in depleted reservoirs if high mud weights are needed to keep normally pressured zones stable. Another area where fluid invasion plays a major role is in promoting instability and lost circulation in low permeability microfractured formations.

In this paper we present an invasion control additive that is formed by the association of hydrophobically modified polymers. These polymers can be used in water-, oil- or synthetic-based wellbore fluids to greatly reduce fluid invasion. We discuss their mechanisms of action, and show laboratory data on invasion control, formation damage and differential sticking. Finally, we present field cases to show the ability of the materials to limit fluid invasion in permeable matrix, stabilize microfractured shales, and protect fragile formations from losses during cementing operations. In addition to applications in depleted zones and microfractured formations, the materials have great potential for use in areas such as poorly consolidated sediments (including shallow sands in deepwater environments), open hole completions and coal beds.

Introduction

It has long been recognized that it is very desirable to minimize the invasion of drilling fluids, completion fluids, workover fluids and cements into subsurface formations¹. In this paper we consider 3 areas where invasion is important and can be detrimental: invasion into matrix permeability, invasion into tight microfractured rocks and losses into fragile formations during cementing.

1/. Matrix invasion

In the reservoir, low invasion can equate to low formation damage and therefore to higher well productivity. Low fluid invasion also helps in the

interpretation of many logs and in obtaining representative formation fluid samples. More generally, high invasion into permeable formations introduces a greater risk of differential sticking than when invasion is kept low.

These concerns, and hence the need for a very low invasion fluid, are further increased in those depleted formations where rocks at normal or original pressure are exposed in the same section as the depleted zones. High mud weights will then be needed to control wellbore instability in the normally pressured zones, resulting in undesirably high overbalance pressures in the depleted horizons.

2/. Invasion into microfractures

Fluid invasion can also lead to severe problems in low permeability microfractured formations, which are now known to be quite common and widespread²⁻⁶. Instability may occur when overbalanced drilling fluid invades the fractures, raising the pressure in the fractures to that of the circulating mud system. This means that the drilling fluid offers no wellbore support, as would be the case in a non-fractured formation. The fact that the matrix permeability is very low adds 2 factors not present if the fractures are in a more permeable rock:

- Because there is no significant leakoff of fluid into the matrix, the volume of fluid flowing into the microfractures is too low to allow a filter cake to form with conventional mud additives: hence the fractures are not protected by a filter cake.
- The pressure in a microfracture does not bleed off into the matrix, as it would if a filter cake at the wellbore surface protected a microfracture in permeable rock.

The effect is illustrated in Figure 1. When the drilling fluid invades into the microfractures, not only is the stabilizing effect of the mud overbalance lost but also the fractures are forced apart and "lubricated" by the mud. These events reduce the friction angle of the fractures and further weaken the structural integrity of the wellbore^{7,8}. Some workers believe the effects are worse in oil- and synthetic-based fluids than in water-based.

While the wellbore may fail and become weakened by the invasion of drilling fluid into the fractures, significant volumes of cavings may not be produced until a further stimulus is applied to the wellbore. This could, for example, be a drop in wellbore pressure when mud circulation is stopped, or swab pressures associated with a trip, or impacts from the rotating drill string. These effects are summarized by Last et al⁶ who observed massive cavings events during wiper trips in wells in the Cusiana Field in Colombia.

3/. Formation breakdown and losses during cementing

Losses during cementing can occur in fragile formations (whether depleted or normally pressured) and where loss zones are exposed. Cementing losses can lead to poor zonal isolation, cement tops not reaching or staying at their planned heights, wellbore instability and other problems that often need remedial cement jobs or recompletion to correct the problems. Losses can be reduced during primary cementing by using staged cement jobs or lightweight cements, but these procedures are expensive and are not always successful.

This paper focuses on the invasion of wellbore fluids into matrix permeability and microfractures (whether naturally occurring or induced). The paper initially describes the more traditional approaches used to control fluid invasion, emphasizing the benefits and limitations associated with each of them. We also discuss recent technology introductions, focusing on aerated fluids and on a novel family of ultra-low invasion fluids containing associative polymers. These novel fluids are discussed in detail, including their mechanisms of action and why they are well suited to a wide range of fluids and environments. Laboratory results and field cases are used to demonstrate the utility of these new fluids in reducing the effects of fluid invasion during drilling and cementing operations.

Controlling Invasion

1/. The Traditional Approach: Particle Bridging

a). Matrix permeability

Our industry is well aware that minimizing invasion of wellbore fluid into rock is a key part of the strategy for successfully drilling and completing a well. An established approach is to add particles to the fluid to bridge at pore throats. If the formation pore sizes are known, these particles can be sized to provide effective cake building properties. Calcium carbonate and salt (sodium chloride) are the most commonly used solids because it is reasoned that acids or other wash fluids can remove them from inside the rock pores, should stimulation be necessary.

The approach requires the particles to penetrate a small distance into the rock and find a suitably sized pore to bridge. How efficiently this happens depends on

the particle size distribution and concentration of particles in the fluid the moment the formation is exposed. If for any reason the optimum sizes and concentrations are not present, effective bridging will not take place and the fluid (both liquid and solid components) may penetrate deeper into the rock. To demonstrate this Figure 2 shows sand beds exposed to fluids containing differently sized solids; deep invasion can be clearly seen when the particle size distribution is not appropriate for a specific sand bed.

An issue with sized solids muds is that the particle size distribution changes as drilling progresses. This is because the sized solids are ground by the action of the bit and mud pumps, and other solids (e.g. drill solids) are incorporated into the system (an added complication with salt crystals is that they also dissolve and recrystallize as they are warmed and cooled during circulation). Maintenance of a size distribution that guarantees good sealing against a particular rock is therefore difficult and the fluids engineer is not always successful in being able to run a low invasion / low damage mud.

The use of bridging solids can be very effective in homogeneous formations where the pore size distribution of the rock is known prior to drilling. However, most permeable sections are heterogeneous and the pore size distribution can vary both vertically and horizontally within a field, making it difficult, if not impossible, to maintain the optimum particle size distribution in the fluid. Continuous seepage losses are one indicator that this sealing is not effective. In this case solids invasion might be deep, making it difficult and costly to remove the resulting formation damage.

b). Microfractures

As previously stated, the key point is to avoid invasion of wellbore fluids into microfractures¹¹. If we assume that no microfractured formation is stable enough to be drilled in underbalance, an overbalanced fluid must be used and invasion of fractures is always likely.

Most attempts to control invasion and instability have been aimed at blocking the entrance to the microfractures, thereby preventing invasion of the wellbore fluid. Materials used for this purpose include micas, fibres, sized solids and deformable materials such as gilsonite and asphalts. Each material suffers some drawbacks:

- Micas work by bridging at the fracture opening and need to be used at a sufficiently high concentration to work quickly. This high concentration can have an adverse impact on the mud rheology, increasing the equivalent circulating density, and therefore possibly increasing invasion. Also, an imperfect seal is formed and so continued filtrate invasion is not

prevented.

- Fibres will form bridges over some microfractures but will not produce a low permeability barrier. Hence they will not prevent fluid invasion and wellbore instability.
- Sized solids: Since there is much less spurt loss into a microfracture than into a permeable matrix, it is unlikely that a protective cake will be produced. To be fully effective, the solids would also need to be sized for the specific fracture size: this is a particular problem in these formations where the fracture widths are generally not known. Sized solids often need to be used in high concentrations (30ppb or higher) and this can adversely impact mud rheology which itself can promote wellbore instability in microfractured formations.
- Deformable particles such as gilsonite and asphalts have probably been the most successful additives in controlling instability in microfractured formations to date. These materials have some ability to deform into, and plaster over, fracture openings of variable size and hence can confer some wellbore stability. However, they have by no means solved the problem. One issue is that some of these materials need to be used at temperatures above their softening points, and these temperatures are not reached in many microfractured shale formations. Also, there are some concerns over the formation damage characteristics of these materials should the mud also be planned for use in payzones.

Even though bridging with sized and/or shaped solids can be effective in many situations (as suggested by the wide uptake in the industry), an approach that did not rely on knowing the formation pore or fracture sizes accurately would be more convenient from the standpoints of design, maintenance and effectiveness. We will now discuss these new approaches to fluid design that embrace this principle of flexibility.

2/. Aerated Fluids

Aerated fluids have been used for drilling low pressure and depleted zones for some time. In their simplest forms, aerated fluids consist of mists and foams. These are low density fluids that can be used to maintain a minimum overbalance while drilling a depleted zone, however they will be of no use if a normally pressured zone is also exposed in the same hole section.

Foam has the merit of being a highly structured fluid of air bubbles contained in a continuous network of liquid films. The structured nature of the fluid, and the often wide size distribution of the air bubbles means that foam has the ability to bridge a range of pore sizes, even

extending this ability to small fractures.

There are, however, some disadvantages to foam:

- Specialized equipment is required to generate foam. This may be costly and, in offshore locations, limited deck space may preclude its use.
- Foam is compressible and so loses some or all of its structure (and hence bridging properties) under downhole conditions. Downhole density and rheology can become difficult to predict and control.

Recently, a new class of aerated fluids, known as aphrons, has been applied in a range of drilling conditions, including depleted zone drilling. These fluids have been extensively discussed elsewhere^{12,13}. Several claims are made for aphrons, including the fact that the bubbles are able to form a barrier to invasion in the near-wellbore formation: hence they can control formation damage, mud losses and other problems associated with fluid invasion. Good success is claimed in certain oil and gas provinces but there are some unresolved issues that surround the fluids at this time. In particular, the aphron air bubbles compress as pressure is applied and, above a critical pressure, collapse and dissolve into the base fluid; hence any benefit of having bridging bubbles in the fluid is lost. Additionally, the relatively high levels of polymers and surfactants have raised concerns among some workers about formation damage. It is also possible that formation cleanup will be difficult if pores are blocked with air bubbles (the Jamin Effect).

3/. Controlling Invasion with Associative Polymers

In the previous sections we have seen how the concept of bridging pores as a way of limiting invasion and damage has developed over recent years. First, the industry developed sized solids fluids in an attempt to seal pore throats quickly and effectively. Air bubbles – whether foams or aphrons – have also been applied. These latter fluids benefit from having “particles” that have both a broad size distribution and are deformable. We have discussed the advantages of both approaches but have also argued that neither provides the solution to the challenge of limiting fluid invasion into matrix permeability or microfractures. With these shortcomings in mind, we set out to define the “perfect” fluid for these formations. We identified the following ideal set of properties:

- The fluid should be able to bridge a wide range of pore throat or microfracture sizes without having to change the formulation.
- The bridging should be rapid and at, or very close to the rock surface.
- To allow use in the payzone, any protective barrier must be easily removed at an appropriate point in the well completion and production process.

- The fluid should not damage producing formations.
- Any barrier formed should continue to function at high overbalance pressure, allowing use in depleted zones. Ideally this barrier should not allow wellbore pressure to be transmitted fully to the formation; this would effectively raise the fracture gradient where that was required.
- The fluid should function over a wide range of densities, temperatures and downhole pressures.
- The same properties should be obtained in oil-, synthetic- and water-based fluids.
- Fluids should be easy to mix and maintain.
- Any additives should be non-toxic and satisfy environmental and human health requirements.

While appreciating that it would be extremely difficult to satisfy all of the above requirements, we screened a number of additives and systems before identifying an approach that, under most conditions, met all of the demands. These “Non-Invasive Fluids” (NIF) were extensively tested in the laboratory before being applied in the field where evidence is growing that the fluids are indeed capable of fulfilling many of the above requirements. (Note: we use the term “Non-invasive Fluid” to identify the fluid from more conventional systems. However, we are not aware of any fluid that does not invade to some degree; the NIF should be considered as a fluid that exhibits ultra-low invasion properties).

The heart of the NIF system is a blend of mostly non-ionic polymers that are modified to produce a range of water and oil solubilities (i.e. the polymers cover a wide range of HLB values).

When added to a water-based fluid, some of the polymers in the blend dissolve to provide fluid loss control similar to conventional additives. However, other species only partially solvate because of their oil-loving characteristics; these polymers associate into deformable aggregates or micelles (*we use the term “micelle” frequently in this paper, although the associations formed by the polymers do not have the structural order of surfactant micelles. In addition, the polymer “micelles” referred to here are much less affected by changes to their environment (salinity, temperature etc) than are surfactant micelles*). The material provides excellent invasion control by quickly forming a very low permeability layer rich in micelles on a rock. This greatly reduces any further ingress of solids or fluid. The micelles in the layer are deformable so, if the pressure is raised, they compress and reduce the barrier permeability even further. The mechanism is depicted in Figure 3.

Particle size analysis suggests that the micelles range from a few microns (μm) to about 1000 μm in diameter (the d_{50} is around 60 μm , the d_{10} is 9 μm and

the d_{90} 340 μm).

In some respects, the micelles act like the water droplets in invert emulsion oil muds; these water droplets are known to concentrate in the filter cake where they make a major contribution to the invasion control seen with oil muds. The major difference, and benefit, of the micelles is that they are more deformable and have a broad size distribution; hence they are better sealing agents and work over a much wider range of pore sizes and permeabilities.

Because of the range of oil and water solubilities in the blend, the additive works equally well in oil- and synthetic-based muds as in water based; in hydrocarbon fluids, the oil soluble components dissolve instead of forming micelles while the water-soluble entities form the micelles – a reversal of the roles in a water mud.

As well as greatly reducing invasion into pores and existing microfractures, the additive has the ability to protect weak formations against pressure transmission and fracturing by functioning as a very low permeability barrier. This effective increase in fracture gradient widens the safe drilling window and has great potential for improving drilling performance not only in microfractured formations but also in depleted zones, poorly consolidated sands, etc.

Cleanup of the protective barrier in reservoir applications is easy because the micelles only exist above a critical concentration of polymers in the fluid. Therefore when contacted by a wash fluid or completion brine that is free of the polymers, or when contacted by reservoir fluid as the well is brought on production the layer simply disperses and is removed in the produced fluid.

The most effective additive concentration is between 3 and 8ppb. The optimum within this range depends on the base fluid properties and the permeability of the formations being drilled (e.g. higher concentrations will typically be required to protect very permeable formations and to give good invasion control in low solids fluids and in high salinity brines).

Laboratory Test Results

The low invasion properties of a fluid containing the associative polymers can be demonstrated using the sand bed invasion test shown in Figure 4. To perform this test, approximately 350 ml of sand is poured into the clear plastic cylinder and gently tapped to level the surface. The grade of sand is selected to represent as closely as possible the permeability and pore sizes of the formation to be drilled. The cell is then filled to within about 1 cm of the top with the mud under test and is reassembled and pressurized to 100psi. The depth of invasion, which can be easily seen through the wall of the cell, is measured as a function of time (alternatively, the sand bed can be saturated with water or oil before the mud is added and the volume of expelled fluid used

as a measure of invasion). The test is typically run for 30 minutes. The ability of the NIF fluids to reduce mud invasion greatly is illustrated in Figures 5 and 6. Figure 5a shows a field oil-based mud that invades deep into the sand bed. Figure 5b is the same mud, but with 5ppb of the micelle-forming polymer added. Figures 6a and 6b show sand bed invasion tests on a hematite-weighted field water-based mud and the same mud containing 5ppb of the micelle-forming polymer blend. Further comparisons of the invasion characteristics of muds with and without the NIF additive are made in Table 1.

We discussed earlier the pros and cons of sized solids muds, stating that the particle size distribution of these solids change during drilling and the good invasion control offered by the freshly prepared fluid can be lost. Figure 7 demonstrates this point by showing how the sealing properties of a sized calcium carbonate fluid change quickly. The fluid, taken from a North Sea well, had a good sand bed sealing capability before drilling started but within 12 hours invasion into the sand bed had more than trebled. Interestingly, when 5ppb of the NIF product was added to the degraded fluid the sealing capacity was improved beyond that of the original sized carbonate mud.

1/. Preventing Formation Damage

Damage mechanisms have been discussed extensively elsewhere¹⁴⁻¹⁷. The basic mechanisms involve either the physical blocking / restriction of pore throats (solids invasion, fines mobilization, polymer invasion, clay swelling, scale, etc) or relative permeability changes (fluid blocks, emulsions, wettability change, etc). Whatever the potential damage mechanism, the first step should be to reduce mud invasion to as low a level as possible on the basis that if mud cannot invade, it cannot damage the formation. The second step, accepting that some invasion always occurs with a mud in overbalance, is to ensure that those species that do invade are selected to cause as little damage as possible.

The NIF concept described here is focused on reducing invasion to as low a level as is feasible. The fact that the micelle-forming additive is compatible with all common mud additives means that the second step (damage from the little filtrate that does invade) can be addressed without compromising the low invasion characteristics bestowed by the micelles.

A key feature and benefit of NIF fluids is that the low permeability barrier of micelles forms quickly and at (or very close to) the exposed rock surface. This means that solids and most polymers are kept from entering the pores, and only the filtrate invades a short way into the rock matrix. This near-surface barrier can be seen in the sand bed experiment shown in Figure 5b.

Because the barrier is located at the rock surface, it is not surprising that low flow initiation pressures are recorded in a formation cleanup experiment. This,

combined with the fact that the micelles break up when exposed to the produced formation fluid, means that excellent return permeabilities are generally obtained in laboratory tests. The location of the barrier at the wellbore wall also makes it accessible to wash fluids should this cleanup option be chosen in place of back production.

This easy cleanup is a major benefit in depleted reservoirs where the problem is potentially made worse because the overbalance may be higher (producing more invasion) and the reservoir pressure lower (giving a lower drawdown to clean up any damage).

Laboratory-derived return permeability data are shown in Figures 8 and 9. To obtain a low damage fluid it is important to add sufficient of the micelle-forming polymer to establish a fully effective protective barrier. In a low-solids fluid, this concentration may be as high as 7 or 8ppb, while in a solids-laden mud (where the solids will contribute to barrier formation in synergy with the micelles) this can be expected to reduce to 3 to 5ppb. The optimum concentration should always be determined on a mud-by-mud basis using the sand bed test cell.

2/. Differentially Stuck Pipe

Once the drill string contacts a permeable formation the mud overbalance pressure acts on the string to force it against the wellbore wall. If this pressure is sufficient, and the filter cake forms a seal around a portion of the string, the pipe will become differentially stuck. The properties of the mud filtercake are an important factor in differential sticking. If the cake is thick, sticking is more likely to occur than if it is thin because the area of contact between the cake and pipe is increased¹⁸. An NIF fluid helps prevent differentially stuck pipe because a very low permeability barrier is formed rapidly, so the filter cake thickness does not increase as rapidly as with most conventional muds. The risk of stuck pipe is therefore significantly reduced when using the NIF. The reduction in sticking potential of muds containing the micellar additive is shown in Figure 10. These results were obtained using a small scale differential sticking tester similar to the device described in reference 18.

3/. Whole Mud Losses

Seepage losses: The micelles formed by the polymer blend are present in a broad size distribution and hence work over a wider range of rock pore sizes, up to and including microfractures¹⁹. This enables the same fluid composition to seal a wide range of formations effectively. Laboratory tests with sand beds have shown that the fluid is capable of controlling invasion into formations with permeabilities well in excess of 20 Darcies. With coarse solids added to an NIF, preliminary laboratory results indicate that even higher permeabilities could also be drilled without significant losses.

Preventing Initiation of Severe Losses: When some formations are drilled at moderate or high overbalance there is a real risk of inducing fractures and initiating severe mud losses. In several field applications there have been good indications that the NIF fluid can increase the fracture gradient relative to that measured with a conventional fluid. There are 2 rock mechanics arguments that can explain how the formation of the low permeability NIF barrier can result in an increase in fracture gradient:

- A very low permeability barrier on or near the wellbore wall will isolate the pore fluid from the wellbore fluid. Because the fluid hardly penetrates into the formation, the pore pressure may not be raised as much as with a conventional fluid, the effective stress will not be reduced so much and the wellbore should be less prone to fracturing.
- Should a fracture initiate because of excessive overbalance for a given micelle concentration in the fluid, the micelles in an NIF will form a barrier in the fracture and a form of "tip screen out" can occur. Therefore, if a fracture is initiated, its propagation should be slowed or stopped and severe mud losses prevented or reduced.

Laboratory experiments are planned to investigate both points further.

It is the ability of the micellar additive to strengthen weak formations and raise the fracture initiation pressure that led us to investigate the use of the material in cement spacers when cementing fragile formations. We envisaged that these spacers could have application in several areas, including the cementing of depleted zones, poorly consolidated formations and easily fractured rocks. In the following section (Field Histories) we show the use of the spacer in successfully cementing coal beds where previously large-scale losses of cement were experienced. Not only does this introduce a new generation of cement spacers, it also lends weight to our argument that the associative polymer is capable of raising the fracture gradient of many formations by significant amounts.

4/. Sealing Microfractures

It is difficult to design laboratory tests to confirm the ability of a fluid to seal microfractures in a low permeability material. It is possible to construct slots of 100 microns or smaller in steel cylinders, but while it is easy to carry out tests with free flow of mud through the slot, this is not what happens in a microfracture where the flow volume is small, and presumably almost stops once the pressure in the microfracture increases to that of the wellbore. It is difficult to mimic this rapid increase in pressure accompanied only by a small spurt loss and, at the same time, determine the crack blocking potential

of fluids. To do this effectively, a much larger scale experimental set-up with small but controlled fluid leakoff into a long slot would be required.

Notwithstanding the difficulties in designing a meaningful experiment, a major North Sea operator has carried out some tests to evaluate the sealing potential of the associative polymer additives in oil-based muds using a preformed fracture. The test used a 6" long fracture between steel plates. The fracture tapered from an opening of 1mm to an exit 0.5mm wide. In the test, the base OBM could not seal the fracture when pressure was applied but when 10ppb of the associative polymer was added, the mud sealed and held 600psi before failing. While this is by no means an ideal experiment, it does indicate the ability of the additive to plug fractures much larger than the size of the individual polymers that make up the micelles.

Field Histories

1/. Field Evidence for Low Invasion

We have already shown how the micelles contained in an NIF can greatly reduce invasion in a laboratory sand bed test. The most direct way of determining this in the field is to use a well logging technique that is capable of profiling fluid invasion into downhole formations. Figures 11a and 11b show logs obtained from an induction array tool in an offshore well in the Far East. The logging tool is capable of detecting invasion up to 90 inches into a permeable formation²⁰. Figure 11a shows the log obtained from a well drilled with a standard synthetic-based mud. Over the permeable section indicated in the figure, it can be clearly seen that the induction tool traces looking 10, 30, 60 and 90 inches into the formation are widely spaced; the interpretation of this is that the mud filtrate is invading to 90 inches or greater. Figure 11b shows the induction log for an offset well where the same mud was converted to an NIF fluid by adding 5ppb of the micelle-forming polymer blend. The 10, 30, 60 and 90 inch traces now lie virtually on top of each other, suggesting that the NIF had reduced invasion to 10 inches or less.

2/. Impact on Well Productivity

The low formation damage characteristics of fluids formulated with the micellar additive are demonstrated by excellent well productivity results in a number of wells. Table 2 shows results for 4 wells drilled and completed in 2003 in Latin America. The payzones in these examples were sandstone and the wells used cased and perforated completions. The production figures are presented in terms of P90 (90% confidence), P50 (50% confidence) and P10 (10% confidence) based on offset well performance and reservoir/inflow models. It can be seen from the table that in the 3 wells using the additive the results either exceed all estimates or fall at the top end of expectations. The one well of the four that did not use the additive (Well 2) had a significantly lower

production than the direct offset Well 3. A simple calculation comparing wells 2 and 3 reveals that the cost of the additive was recouped in less than 10 days by the increased oil production.

3/. Wellbore Stability in Microfractured Shales

Microfractured shale and limestone, Colombia, Latin America

In the first quarter of 2003 a major operator drilled an exploration well in a field north of Bogota. The target was a fractured limestone reservoir at approximately 8500 feet TVD.

The original well plan was to set 9 5/8" casing at 5400 feet (MD) and then drill 8 1/2" hole at approximately 35 degrees to 7550 feet (MD) before completing the well in 6" hole at 9200 feet. These last 2 hole sections would penetrate claystones, shales, and limestones before hitting the limestone target. Since all these formations, including the reservoir, were naturally fractured – or prone to induced fracturing – there were major concerns about lost circulation, wellbore instability and stuck pipe, as well as formation damage in the payzone, based on offset well data information.

After discussions with oil company personnel to identify the major risks associated with the well, it was decided to convert the mud from the 12 1/4" section to a low-invasion fluid by maintaining an active concentration of 5-6ppb of the micelle-forming additive in the system. The non-invasive property of the fluid was maintained at the wellsite using the sand bed test previously described.

The water-based mud was converted to the low-invasion fluid once the 9 5/8" casing shoe was drilled out. Drilling proceeded smoothly through the fractured shales and claystones and mud properties proved stable and easy to manage. Typical fluid properties were:

Plastic Viscosity:	35-40 cPoise
Yield Point:	30-40 lb/100ft ²
Gels (10s/10m):	10-14 / 18-23
Density:	13.8 – 14.2ppg
pH:	9.9-10.6
API Filtrate:	3.2 – 5 ml
HTHP Filtrate:	14 – 18 ml
MBT:	12.5 – 20

As drilling continued it became evident that none of the anticipated problems were occurring, despite the fact that these formations had given major problems elsewhere.

As the planned 8 1/2" casing point was reached, the excellent hole condition and stable fluid properties persuaded the oil company to revise the drilling programme. Instead of setting casing and continuing in 6" hole, the decision was taken to drill to TD in 8 1/2" hole. The well TD was reached 5 days later with no mud losses, pipe sticking or wellbore instability problems. The

hole remained stable and in good condition throughout a successful 6 day open hole logging programme.

A key success was the ability to remove a casing string from the well plan because of the properties imparted by the low-invasion fluid. As well as the obvious savings in casing and cementing costs, the extended 8 1/2" hole reached TD in 20 days rather than the 25 days planned for the original combined 8 1/2" and 6" sections. It should also be noted that 5 of these 20 days were lost due to pipe washouts, otherwise it is likely that the section would have been completed in 15 days.

Fractured shales in the reservoir section, Colombia, Latin America.

In 4 offset wells, instability in fractured shales within the payzone resulted in hole enlargement from 8.5 inches to an average of over 10.5 with maximum washouts to 19 inches. As well as causing drilling problems, this level of hole enlargement made it very difficult to cement the wells effectively.

By adding just over 3ppb of the micellar additive to the base mud, the operator was able to drill the 5th well with much less difficulty. The *maximum* caliper in the caliper recorded in the 8 1/2" section was 9 inches and most of the hole was in gauge. Well productivity was at the top end of expectations.

4/. Cement Spacer Applications

An operator in Wyoming commonly experienced severe losses when cementing coal bed methane wells. The problem is not only that the coal beds can contain natural fractures but also that even competent formations are weak and easily fractured by the hydrostatic pressures generated during cementing operations. The low cost of these wells did not justify the use of staged cement jobs or expensive, ultra-lightweight cements and so the operator was resigned to living with cementing losses. The consequences of these losses included impaired productivity, poor zonal isolation and cement tops well below the planned heights (leading to lack of casing support, corrosion concerns etc).

In 2002 the client began a programme using the micellar additive in cementing spacers (termed Non-Invasive Spacer – NIS) to see if the ability to strengthen weak formations applied to cementing as well as drilling operations.

Five wells were cemented using the Non Invasive Spacer. In all cases cementing losses did not occur, cement tops reached and remained at the desired height and good zonal isolation was achieved, as evidenced by cement bond logs and well productivity results.

An Oklahoma operator is currently engaged in a 30-well NIS test program in its coal bed methane drilling operations. Results of cementing operations support the Wyoming findings and the operator is awaiting

production results to determine the full benefits to productivity provided by the NIS.

Conclusions

- By minimizing the invasion of drilling fluids, completion fluids, workover fluids and cements, problems such as formation damage, wellbore instability, differential sticking and lost circulation can be reduced and often eliminated.
- Established approaches to controlling invasion, such as the use of sized solids, have been shown to be valuable but do have some limitations. These limitations include the need to know the size distribution of the rock pores to be protected, the ability to maintain an effective bridging solids size distribution during drilling and the possible detrimental effects of high bridging solids loadings on mud rheology.
- In microfractured rocks, the size of the fractures is generally not known, making it difficult to use a bridging solids approach effectively. Additionally, the bridging approach is probably of limited value in preventing invasion in low permeability microfractured rocks because there is insufficient fluid flow into the fracture to allow a protective cake to form.
- Aerated fluids can offer advantages over sized solids but these also suffer from some drawbacks
- Laboratory testing shows that flexible particles formed by associative hydrophobically modified polymers can produce low invasion fluids that give low formation damage and reduce the risk of differential sticking and lost circulation. Although difficult to test in the laboratory, we discuss why the same principle will stabilize microfractured formations that could otherwise cause wellbore instability and mud losses.
- Field test results confirm the ability of drilling fluids containing associative polymers to improve well productivity and to minimize wellbore instability in microfractured shales.
- Field tests have shown that the associative polymers can also reduce losses during cementing when used in a "non invasive spacer".
- The associative polymers can be used in a wide range of water-, oil- and synthetic-based fluids.

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Table 1: Sand bed invasion results of various drilling fluids, tested with and without the associative polymer additive.

Mud Type	Sand Bed Invasion (Base Mud)	Sand Bed Invasion (With Additive)	Concentration Of Additive (ppb)
Oil Mud 1	Total	1 cm	8
Oil Mud 2	Total	0.5 cm	10
KCl Polymer	Total	4.5 cm	6
KCl Polymer2	Total	1.5 cm	8
NaCl	Total	3.7 cm	5.25
Polymer / Starch	Total	1.7 cm	5
Cesium Formate	Total	6 cm	5

Notes: Sand bed was 20/40 frac. sand. Test pressure 100psi. Test time 30 minutes

Table 2: Well productivity data from Latin American wells

Well Number	1	2	3	4
Additive Concentration (ppb)	3	0	6	3
P90 - P50 - P10 Production Estimates (BOPD)*	600-800-1100	1500-2000-2600	1500-2000-2600	500-600-700
Actual Production (BOPD)	1000	1800	2160	710

* P90 is predicted oil production at 90% confidence level, P50 at 50% confidence and P10 at 10% confidence.

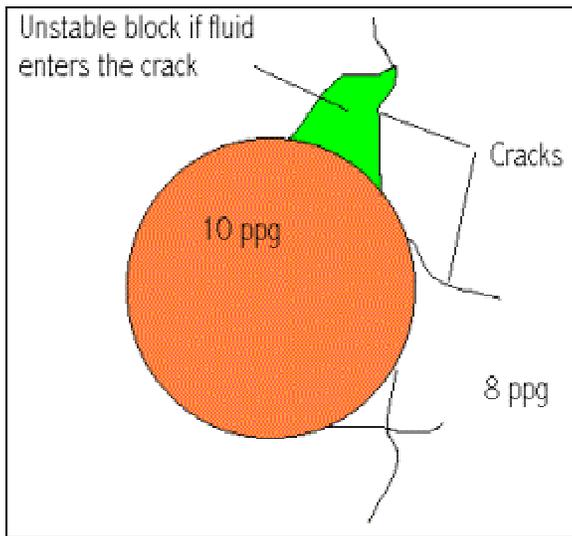


Figure 1 – The wellbore pressure exceeds the formation pressure by 2ppb. The unstable block is bounded by fractures that will pressurize to the wellbore pressure unless the drilling fluid prevents this. Once pressurized, the block is unsupported by the drilling fluid and is liable to collapse.



Figure 2 – A sand bed exposed to different calcium carbonate sizes. From left to right: fine, medium and coarse. If the solids particle size is not appropriate, deep invasion of the solids occurs (left). This can causing severe formation damage and may not effectively prevent mud losses or stuck pipe

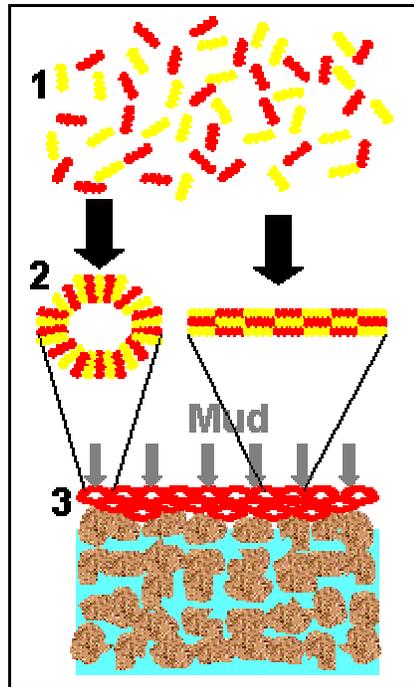


Figure 3 – A schematic representation of the modified polymers (1) forming “micelles” or assemblages (2) in solution. The assemblages form the low permeability, deformable barrier (3) on the rock surface in the very early stages of mud filtration.

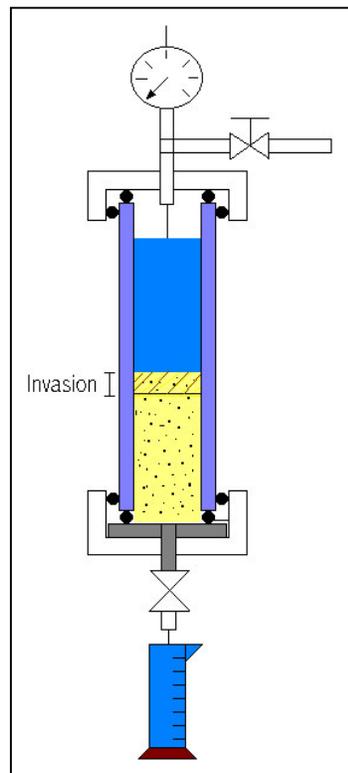
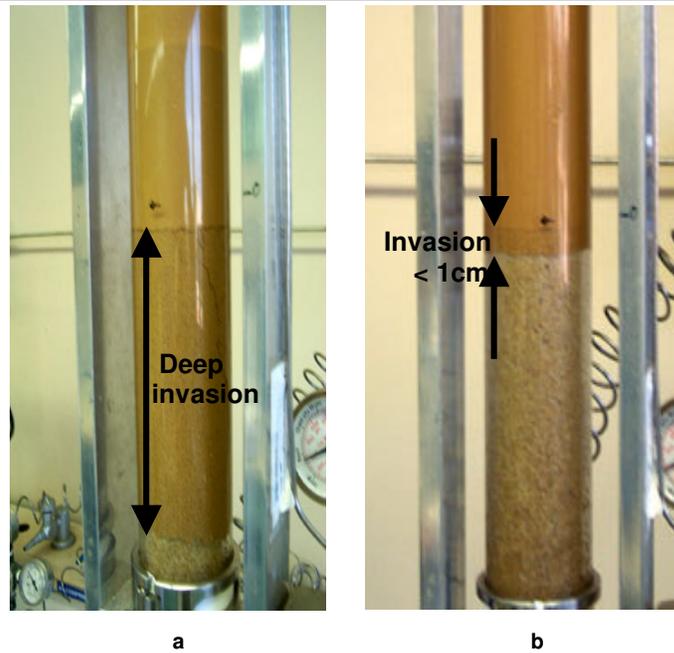
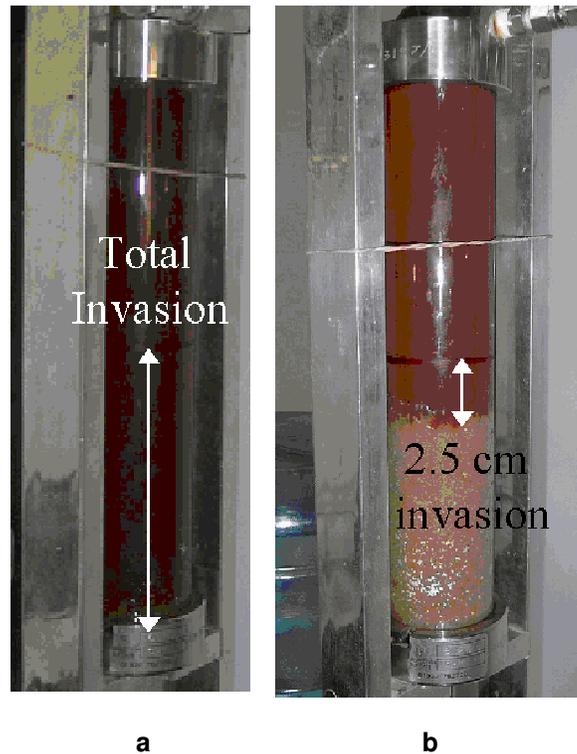


Figure 4 – Diagram of the sand bed invasion test cell. The test is made at 100psi for 30 minutes at room temperature.



Figures 5a and 5b – The left hand figure (a) shows deep Invasion of a field oil-based mud on a 20/40 grade sand bed. The right hand figure (b) shows the same mud with 5ppb of the associative polymer present. The barrier at the sand surface can be seen just below the top arrow.



Figures 6a and 6b – The left hand figure (a) shows deep invasion of a hematite-weighted 16.5ppg field water-based mud from Colombia on a 20/40 grade sand bed. The right hand figure (b) shows the same mud with 5ppb of the associative polymer present.

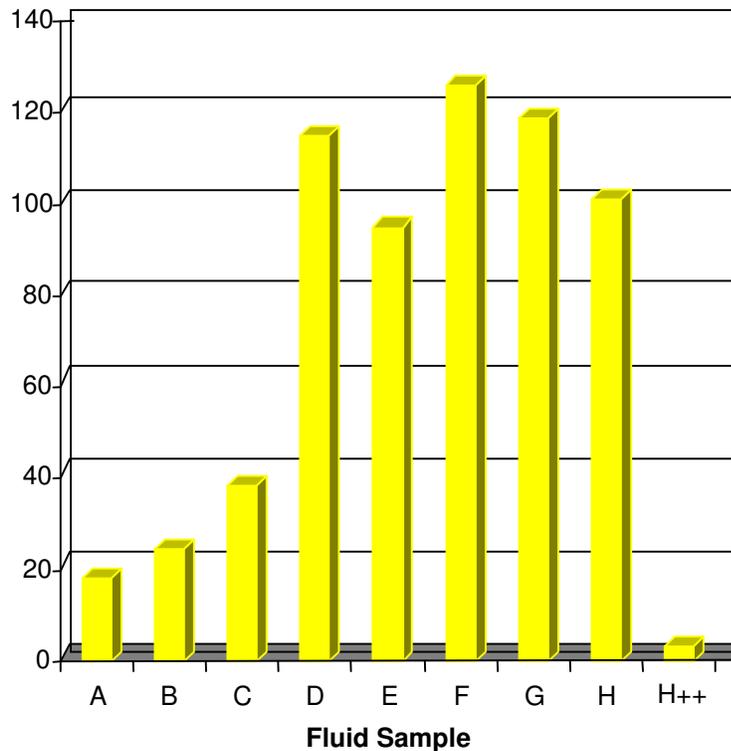


Figure 7 – Sand bed invasion results for a sized CaCO_3 field mud. Samples A-C were taken from the system before drilling commenced. Samples D-H were taken 12 - 44 hours into drilling and show an approximate 3-fold increase in invasion. The last test (H++) was done with sample H plus 4 ppb of the associative polymer. Vertical scale is sand bed invasion volume x 10 (mL).

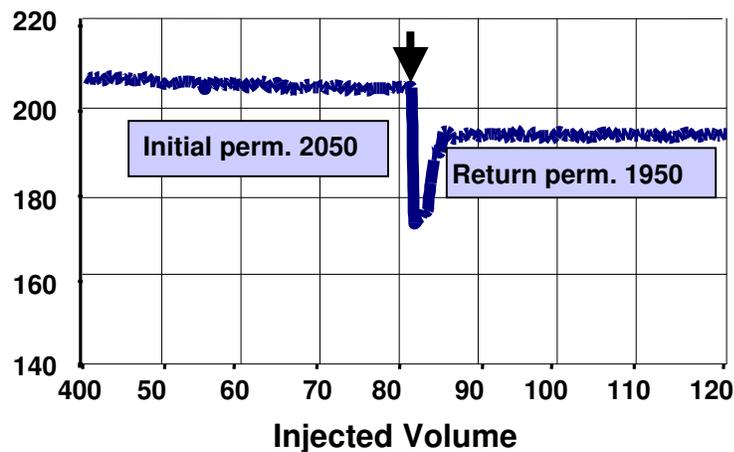


Figure 8 – Return permeability to brine. Arrow denotes point of injection of associative polymer fluid. Vertical scale is MilliDarcies (x10). Fluid is a bentonite water based mud containing 8ppb micelle-forming additive. Core is a natural sample from a South American well. Return permeability = 93%

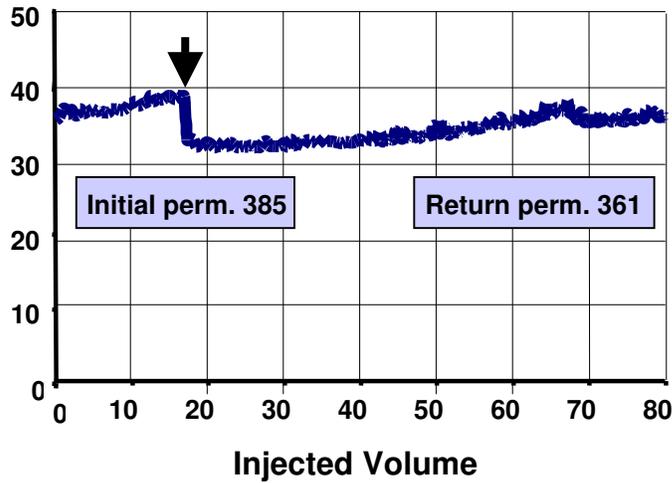


Figure 9 – Return permeability to brine. Vertical scale is milliDarcies (x10). Fluid is a solids-free water based brine fluid containing 6ppb micelle-forming additive. Core is a synthetic aluminosilicate core. Return permeability = 95%.

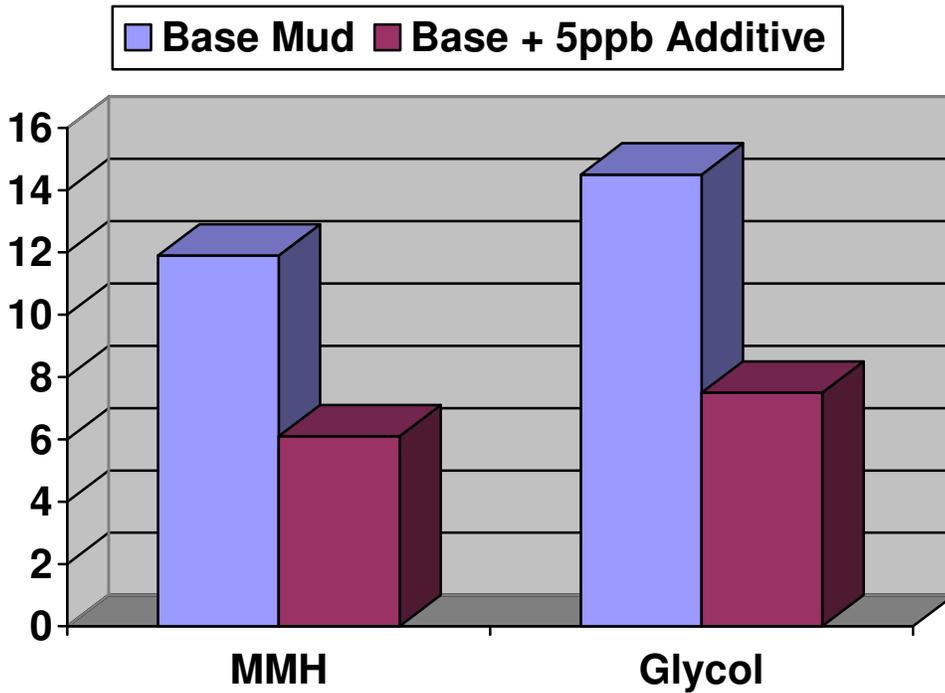
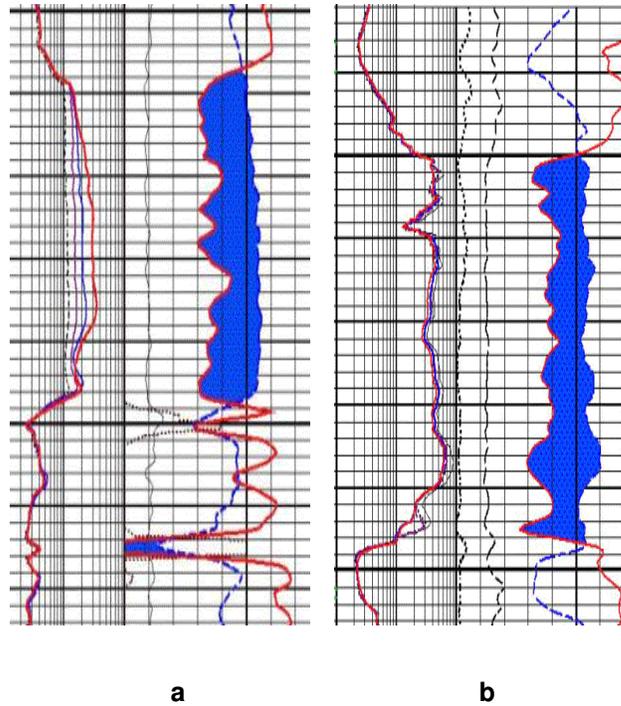


Figure 10 – Differential sticking laboratory test results. Water based muds are at 13ppg. Vertical scale is “sticking index”



Figures 11a and 11b – The left hand figure shows an array induction log of a permeable formation (shaded) drilled with a standard synthetic-based mud. The spaced lines on the left hand side indicate deep filtrate invasion (> 90 inches). The right hand figure (11b) shows an offset well using the same mud but with 5ppb of the micelle-forming additive presence. The overlying lines indicate much less invasion (< 10 inches).