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Emulsified scale inhibitor systems technical report 2000

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Scope:

The project aims to develop emulsified scale inhibitor systems suitable for application as squeeze treatments, particularly in water-sensitive wells and those with poor pressure support. The developed emulsion will be evaluated and the potential benefits demonstrated in the laboratory

Key-words: scale inhibition, emulsion

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S Beare

Project Manager
Steve Beare

S Stokka

for RF - Rogaland Research
Sigmund Stokka

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Summary

This project is targeted towards developing emulsion systems suitable for application as scale inhibitor squeeze treatments in the North Sea. The scale inhibitor is contained in the internal water phase, reducing rock/inhibitor interaction during injection and aiding placement, whilst the oil outer phase will maintain oil continuity during the treatment and hence reduce the drawdown required to restart production. The smaller water volume will also be of benefit in water-sensitive formations.

In the first 2 years of this project a suitable emulsion system was developed and the benefits from its use demonstrated in the laboratory on outcrop rock and for a water-sensitive North Sea reservoir. The work performed this year extended the generic investigation of the emulsion system in three areas;

(1) the relationship between emulsion oil:water ratio and injection pressure into rocks of different permeability,

(2) the effect of rock wetability on emulsion system performance, and

(3) displacement of the emulsion through the formation with an oil overflush.

The data obtained this year has further confirmed the benefit of emulsion systems in terms of the low drawdown required to re-start oil flow after a squeeze treatment in comparison to a completely water-based squeeze treatment. It has been shown that an emulsion slug may be effectively displaced through the formation by an oil overflush, especially in intermediate-wetting rock. It is also easier to inject emulsions into oil-wet rather than water-wet rock. In addition, the work provided insights into field application requirements, and from the knowledge gained in this project the laboratory studies that would be required to optimise an emulsified scale inhibitor for a specific field application have also been identified. A suggested protocol is given as an appendix to this report.

Preface

The work reported here forms part of the Scale Control Beyond 2000 programme, and was carried out under project 2a: Emulsified scale inhibitors. This project aims to develop an emulsified scale inhibitor system suitable for field application, and demonstrate in the laboratory the potential benefits and limitations.

1 Introduction

During 1998/9 the most promising emulsion system was selected from the available candidates based on data from bulk tests of viscosity and breaking performance, and that system was further evaluated in terms of the likely benefits that may be obtained from its use in the field. It was demonstrated in core floods that a similar phosphonate scale inhibitor desorption profile was obtained from both emulsified and 'standard' treatments, and potential advantages were observed for the emulsion system in terms of reduced pressure drop required to instigate oil flow after the inhibitor treatment. The effects of diluting the emulsion with oil to further reduce its water content have been studied in terms of emulsion viscosity and inhibitor return profiles. A preliminary laboratory evaluation of the emulsion system using field materials from a water-sensitive formation showed that the permeability reduction observed after a wholly water-based system was avoided by use of an emulsion.

The work performed this year (2000) and reported here was intended to provide some insight into field application of the emulsion system, and has comprised 3 studies.

The relationship between emulsion oil:water ratio and injection pressure into rocks of different permeability has been investigated by injecting emulsions into short cores below the breaking temperature, and decreasing the O:W ratio stepwise whilst monitoring the pressure drop.

The effect of rock wetability on emulsion system performance was investigated by comparing inhibitor return profiles from native state Berea core (which is strongly water wet), and Berea core which had been aged in crude oil to give it intermediate wetability.

Displacement of the emulsion through the formation with an oil overflush was studied using a 1 metre long core flooding rig with pressure tappings along the core length. The experiments comprised injecting a small slug of scale inhibitor and displacing it along (but not out of) the core with an oil overflush, and following the slugs progress from the pressure change in different sections of the core. After a shut in period the core underwent sequential oil and brine backflushes. The emulsion system was compared to a seawater inhibitor solution in both water-wet and intermediate-wet Berea core.

Finally, all of the data and experience gained throughout the project has been used to prepare a suggested laboratory protocol for optimising the emulsion system for a specific application, together with some aspects of field use which should be considered.

2 Emulsion injection study

The injectivity study was performed to attempt to identify whether there is a predicable correlation between emulsion O:W ratio and the rock permeability into which it may be easily injected. Experiments were performed using Berea of different permeabilities, both native state and modified to be intermediate wetting, and also a field core material.

2.1 Experimental method

This study utilised a different experimental technique than the usual core floods performed in this project in an attempt to identify, in a single test, the limiting oil:water ratio for injection into the rock. In these tests (which were performed at a temperature below the emulsion breaking temperature) the core was initially conditioned to residual brine. A 50:50 O:W emulsion was then injected simultaneously with oil from a second pump. A schematic diagram of the test rig is shown in Figure 1. The ratio between emulsion and oil was altered stepwise, starting with a low emulsion content, whilst monitoring the pressure drop. Approximately 5 pore volumes of emulsion were injected at each emulsion/oil ratio. The intention was to identify the O:W ratio at which pore blocking began by the excessive increase in pressure drop across the core that would result. This technique permits data from emulsions with different W:O ratios to be gained relatively simply on the same core plug.

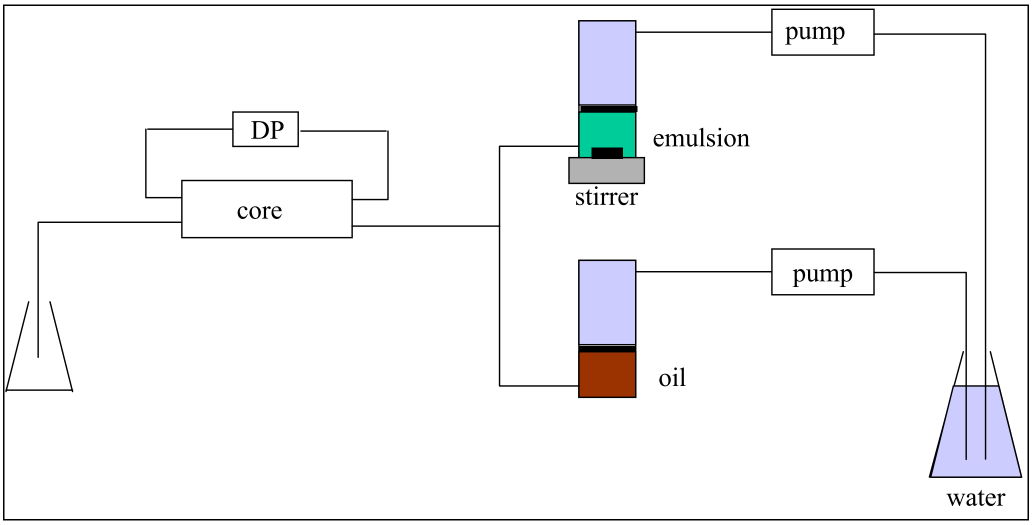

Figure 1. Test set up for emulsion injectivity test

2.2 Results

Two core floods were performed on water-wet Berea rock (100 mD and 500 mD), one on a 400 mD reservoir core plug, and one on a 500 mD Berea plug with modified (intermediate) wetability. The core details are given below.

	Berea	Field core	Berea	Berea (modified wetability)
Permeability (nominal)	100 mD	400 mD	500 mD	100 mD
100% brine	93.3	402	496	273 (oil)
Oil at S_{wi}	70.4	138	371	109
Brine at S_{or}	6.0	67	54	53

Injecting 95:5 O:W ratio emulsion had little effect on any of the rocks. Figure 3 shows the data for emulsion with an oil:water ratio of 90:10. The plots show the pressure drop, normalised for the core plug permeability for ease of comparison, against the pore volumes of emulsion injected. The pressure drop is normalised to the relevant core absolute permeability, rather than either of its relative permeabilities, since it is expected that the emulsion droplets will behave as (deformable) particles, and physical blocking would occur. The pressure drop will also increase in proportion to the emulsion viscosity (shown in Figure 2 at 20°C, cf 60°C core flood temperature). This increase is not take into account in the plots, but from Figure 2 it can be seen that maximum expected would be a 9 times rise for 50:50 emulsion if it behaves as a single-phase liquid when passing through the pores.

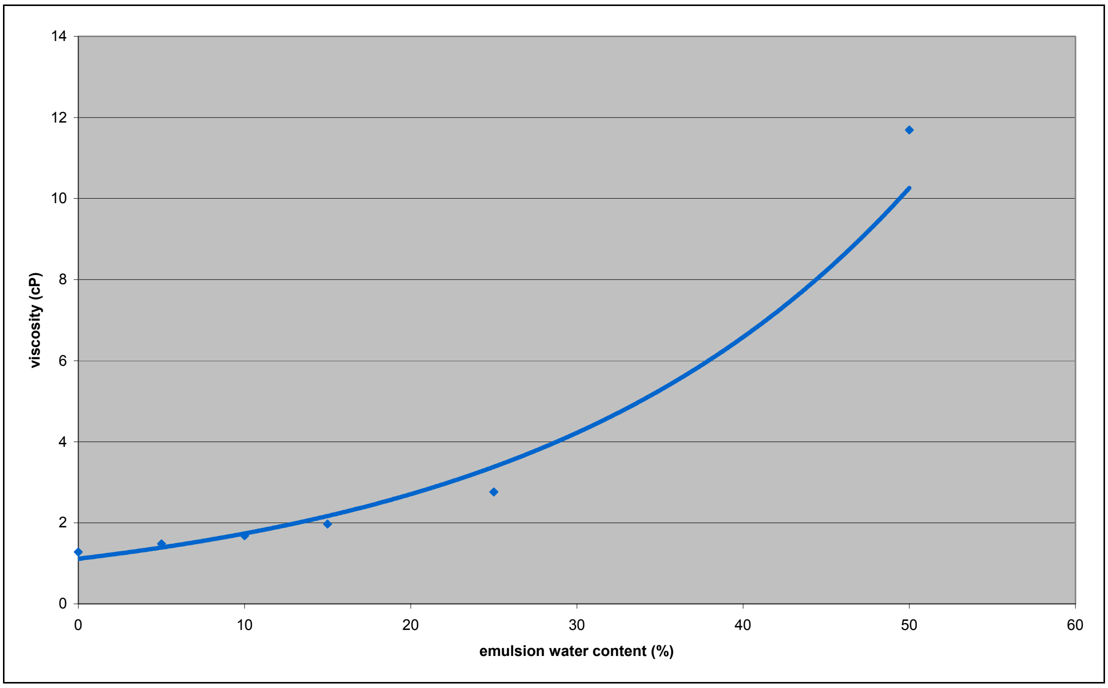

Figure 2. Effect of water phase volume on emulsion viscosity

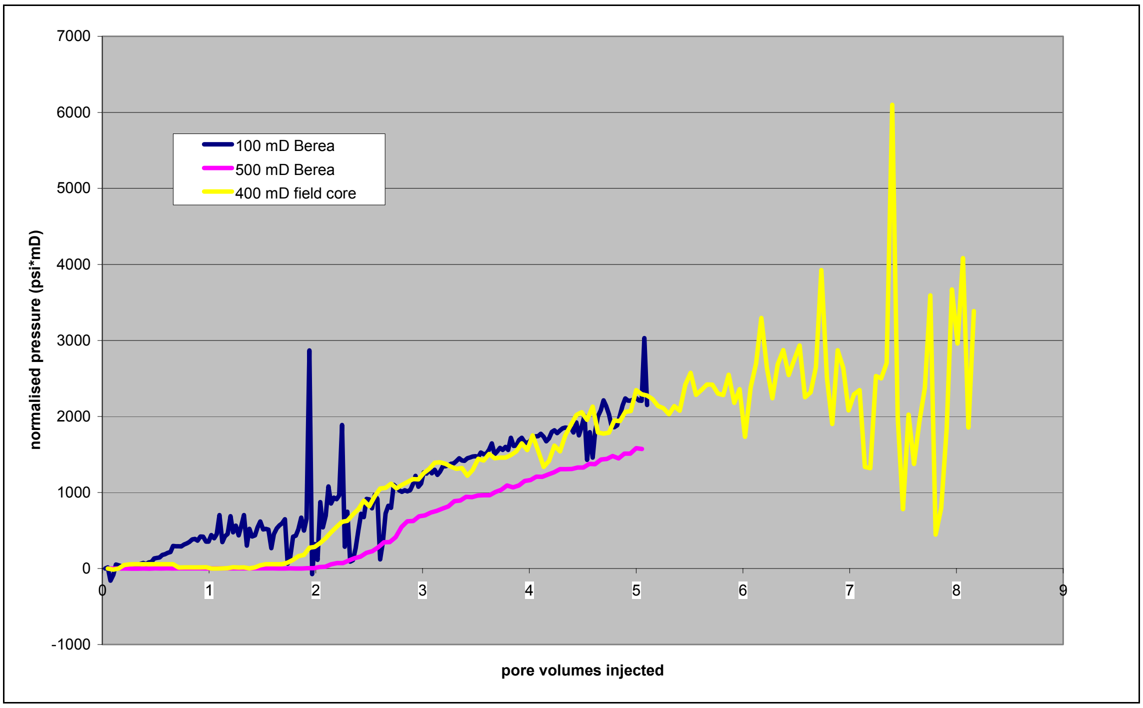

Figure 3. Normalised injection pressure for a 90:10 O:W emulsion

The data in Figure 3 show little difference between the cores, and an equilibrium pressure drop is obtained showing that a steady-state flow of emulsion may be achieved. However, the pressures are much higher than would be expected from the emulsion viscosity alone. Figure 4 shows a similar plot for the 85:15 O:W emulsion, and in this case it can be seen that injection is easier into the 500 mD core. This is the lowest O:W ratio that could be injected into the 100 mD core at this flowrate since the pressure drop exceeded the rig transducer pressure limit. This represents a 500 times increase in injection pressure for the 85:15 emulsion compared to oil alone.

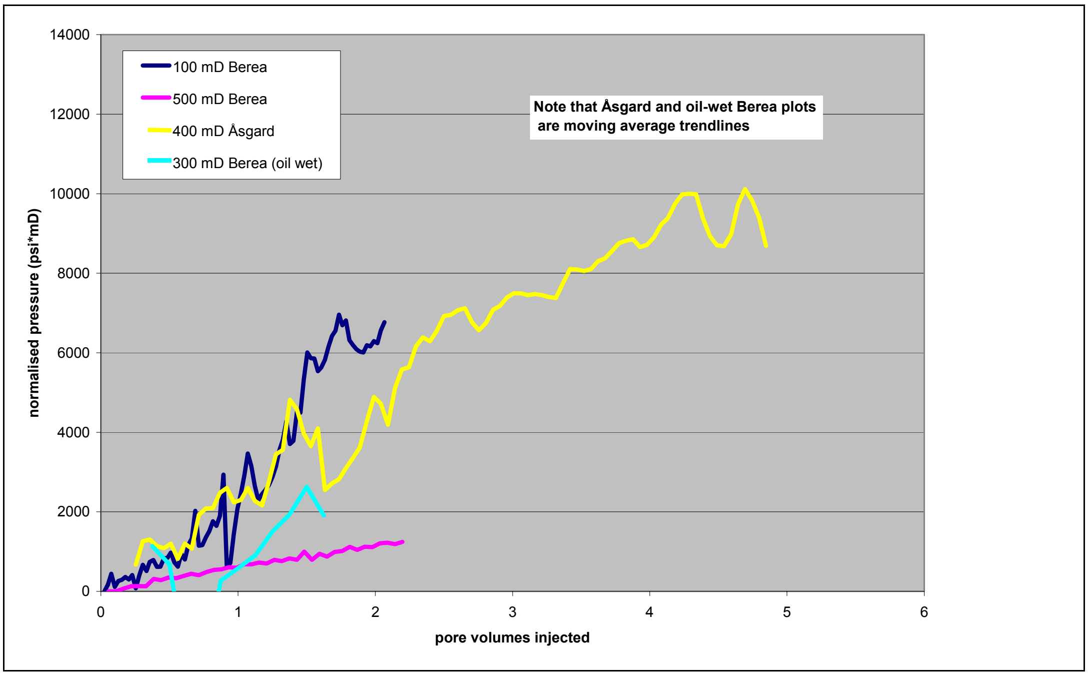

Figure 4. Normalised injection pressure for 85:15 O:W emulsion

Injection was continued into the 400 mD field core up to a 50:50 emulsion, at each stage obtaining steady-state conditions indicative that large volume injection would be possible. The 500 mD water-wet and 300 mD oil-wet Berea cores showed similar behaviour to the 400 mD fieldmaterial.

All 4 cores showed pressure increases greater than would be expected from emulsion viscosity alone, although where experimental constraints allowed a steady-state pressure drop could be obtained indicating a lack of progressive pore blocking/permeability reduction. This suggests that emulsions may be injected in the field provided pressure constraints are not exceeded. A further parameter which will assist field injections is the rock wetability. Data obtained in this project has shown that emulsions are much easier to inject into oil-wet rock, as would be the case in field treatments. This is also shown in the wetability effect study (see below).

3 The effect of rock wetability on emulsion performance

These tests were intended to examine whether the emulsion performance is acceptable in more oil-wet rock than the native state Berea which was employed for most of the research project. Four core floods were been performed, comprising an emulsion test and a seawater solution baseline test performed in 500 mD Berea both modified to be oil wet and untreated (and hence water-wet). The core flood routine was the same in all cases, and comprised ageing the core in crude oil at 80°C for 1 week (if required), conditioning it to residual brine, and then reducing the temperature to 60°C and injecting a 0.2 pore volume slug of inhibitor. The core was then raised back to 80°C and shut in overnight. An oil backflush was performed followed by a 150 PV brine backflush to obtain the inhibitor desorption profile. The core was then flushed to residual brine and the final oil permeability measured.

The pressure drop during the inhibitor injection is shown in Figure 5, and reveals the benefit of oil-wet rock in terms of emulsion injection pressure. The effect of the wetability change is to greatly increase the brine relative permeability without significantly affecting the oil relative permeability (see Figure 6), and so the brine inhibitor solution is also easier to inject. The reduced emulsion injection pressure in oil-wet rock may be due to reduced interaction between the brine droplets and the rock surface, since the oil-continuous emulsion would not be expected to benefit from an increased water relative permeability.

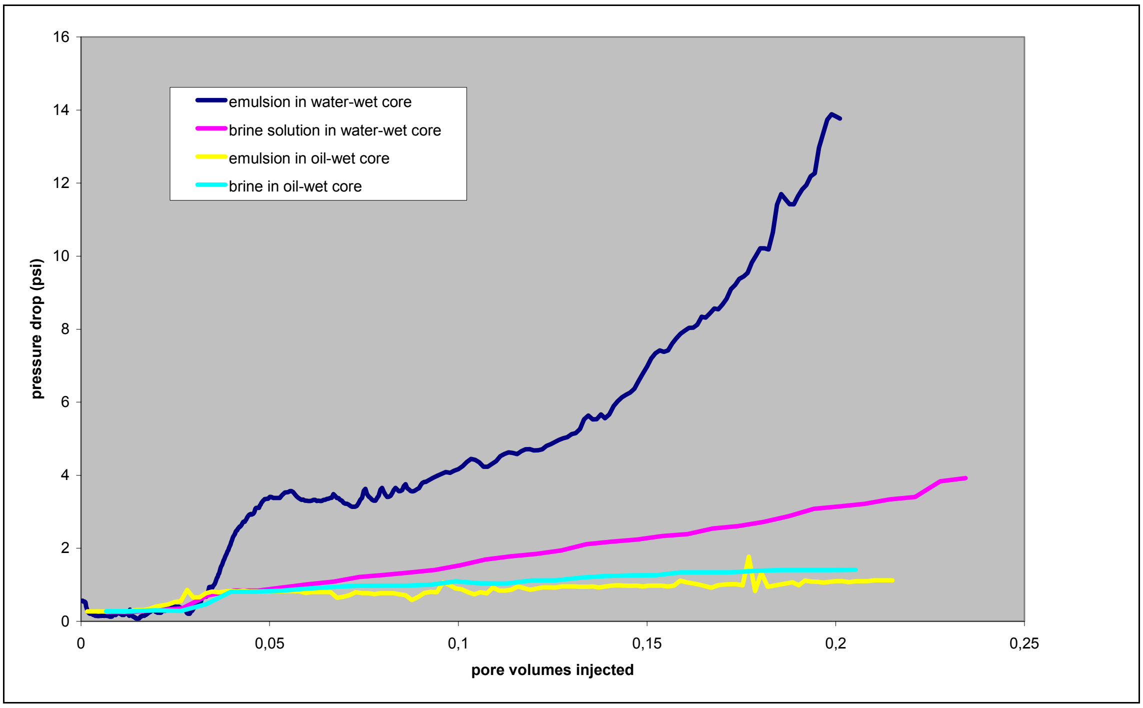

Figure 5. Pressure drop during inhibitor slug injection

The permeabilities measured at different points in the corefloods are shown in Figure 6, and show that the oil permeability is not significantly changed in any of the tests performed; that is, neither emulsion or water-based scale inhibitor treatments alter the oil relative permeability irrespective of the core wetability. However, it can be seen from the data that the scale inhibitor treatment returns the brine relative permeability of the oil-wet core to almost that of the water-wet material. This is an effect of the scale inhibitor itself, rather that the emulsion surfactants, because it occurs to the same degree in both the emulsion and water-based tests. It may be a feature of using water-wet rock modified in the laboratory, rather than a universal effect, since it was not observed during testing with the Scott core earlier in the project.

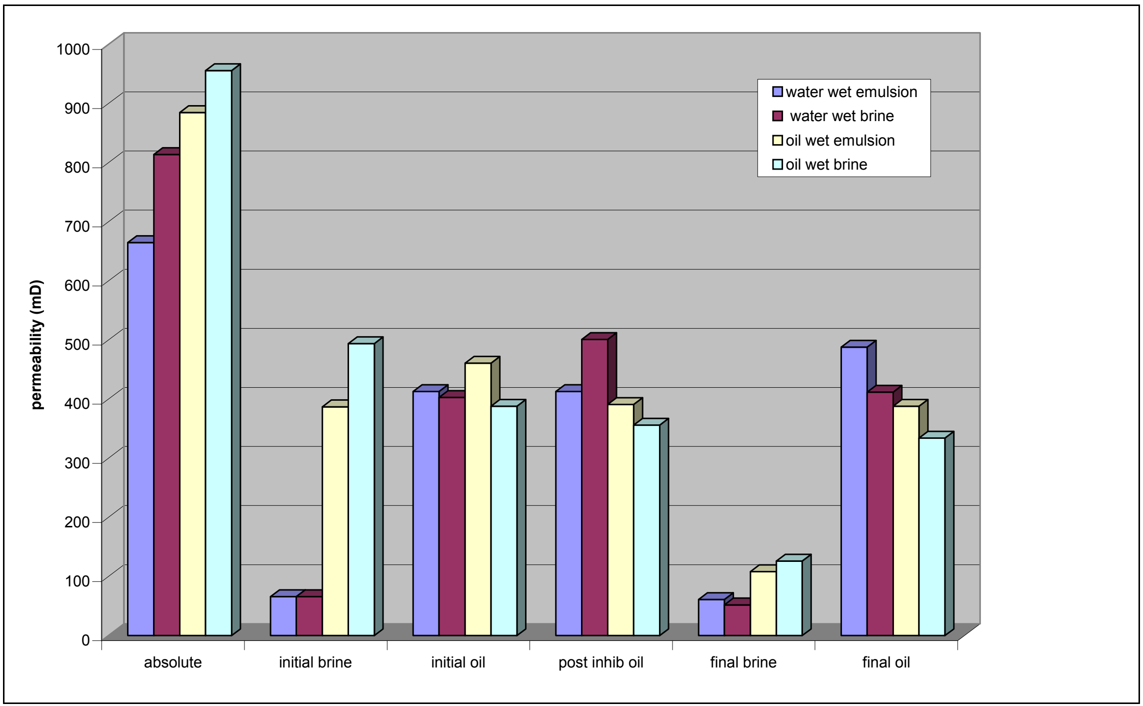

Figure 6. Permeabilities measured during wetability study core floods

If the brine relative permeability change observed here is valid for field treatments it would enhance one of the benefits of emulsion treatments, namely the low drawdown required to re-start flow after shut-in. Figure 7 shows the pressure drops during the oil backflush after the shut-in period for each coreflood. It can be seen that the brine treatment requires a similar pressure increase to re-start flow in both cores, whilst the emulsion treatment flows with no increase in pressure with respect to that required for steady-state oil flow.

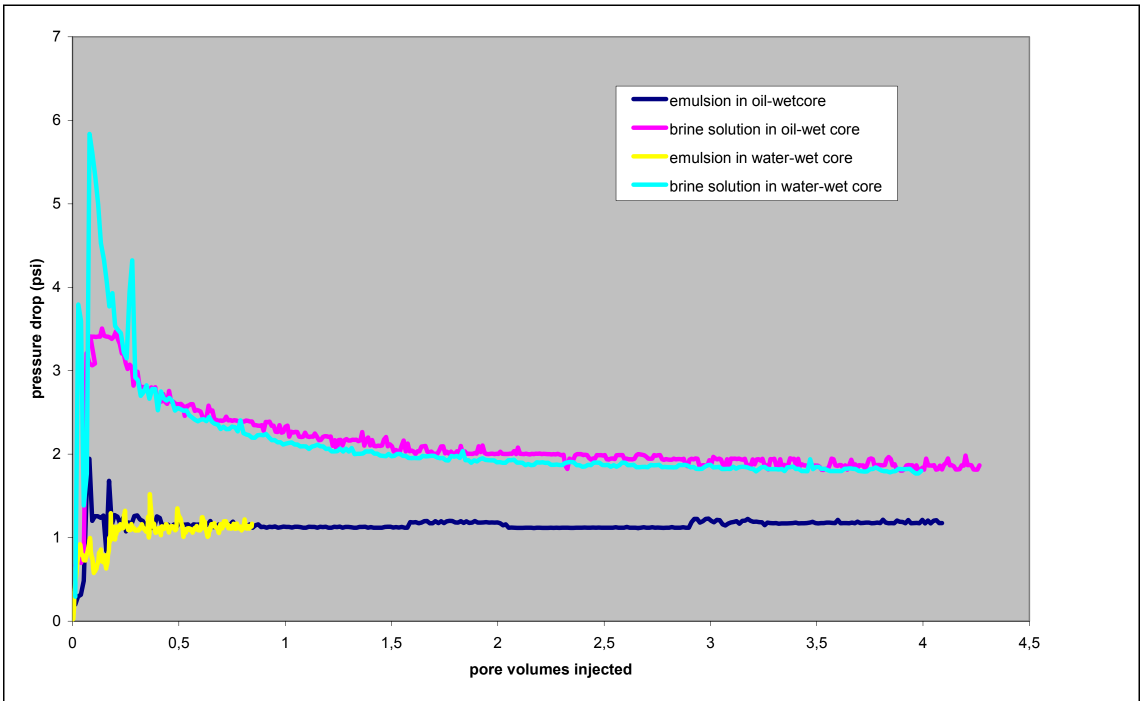

Figure 7. Pressure drops during oil backflush after inhibitor shut-in.

The inhibitor desorption profiles are shown in Figure 8. From which it can be seen that the performance of the emulsion system is decreased in the oil-wet rock, whilst that of the water-based system is enhanced. The reasons for this are unclear, since both treatments returned the wetability of the oil-wet rock to that of the water-wet material. Further work would be required to determine whether this is a real effect, but see also the results from the treatment overflush study below.

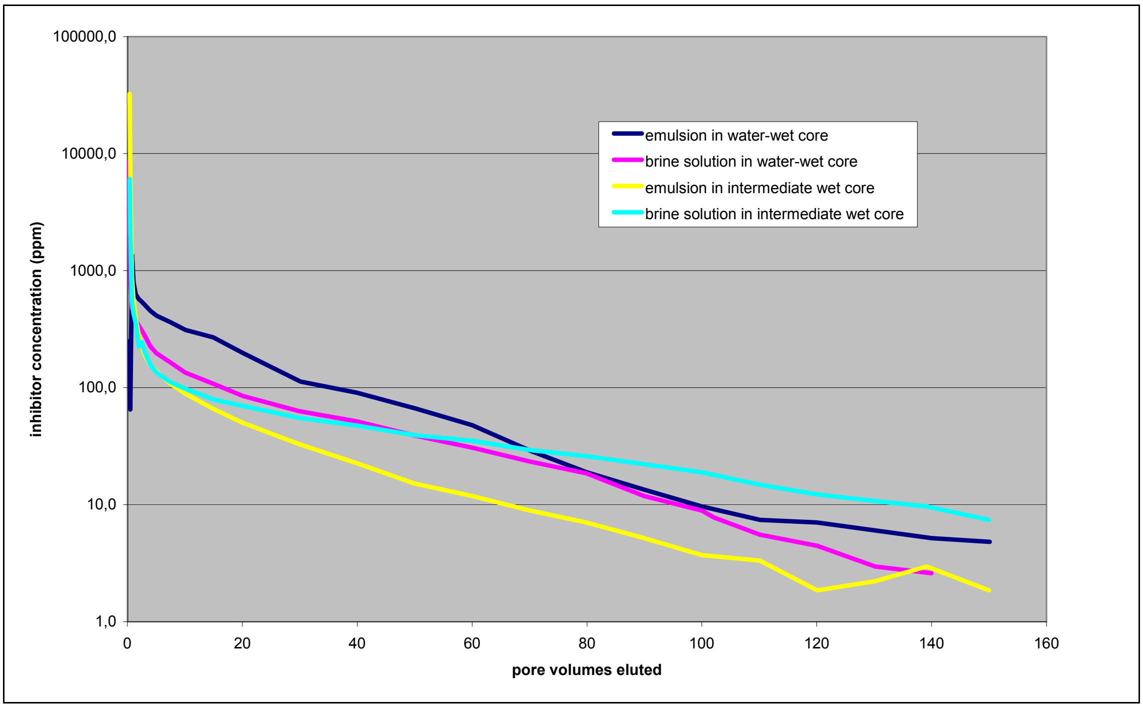

Figure 8. Wetability study inhibitor desorption profiles.

4 Emulsion displacement into the formation by an oil overflush

The purpose of this study was to investigate the displacement of the emulsion system into the formation by the overflush. Since one of the reasons for using an emulsified squeeze treatment is to reduce the water volume injected into sensitive formations, an oil overflush was used. Four tests were performed, all using Berea core material. The tests were in pairs, the first pair being performed in native state (water-wet) core, whilst the second pair used modified core of intermediate wetability. Each pair comprised an emulsion system test and a seawater inhibitor solution test for comparison.

4.1 Experimental method

This study was performed using the 1 metre core flooding equipment. The test facility, and the preliminary results of the experiment using an emulsion system were described in the 1999 Annual Technical Report. This year the baseline test was performed, and the two core floods using intermediate-wet core. The emulsion injected was a 50:50 O:W system diluted 100% with oil, in which the internal seawater phase contained 10% Monsanto D2060S phosphonate scale inhibitor. The baseline floods used the same flood sequence as the emulsion test, except that the inhibitor slug comprised a seawater solution instead of an emulsion. The test sequence for the water-wet tests was:

1. Saturate the core with brine, measure the pore volume.
2. Measure the 100% brine permeability.
3. Apply back pressure, and raise the temperature to 80°C (with brine flowing at a low rate).
4. Measure the permeability to brine.
5. Flood to S_{wi} with 10PV of oil at 2 cm^3min^{-1} in the reverse direction. Measure the volume of brine eluted.
6. Measure the permeability to oil.
7. Flood to S_{or} with 10PV of brine at 2 cm^3min^{-1}. Measure the volume of oil eluted.
8. Measure the permeability to brine.
9. Flood to S_{wi} with 10PV of oil at 2 cm^3min^{-1} in the reverse direction. Measure the volume of brine eluted.
10. Measure the permeability to oil.
11. Reduce the temperature to 60°C overnight (with oil flowing at a low rate).
12. Inject a 0,2 PV inhibitor slug at 1 cm^3min^{-1}. Collect the core effluent to measure the volume.
13. Inject a 0,5 PV oil overflush at 1 cm^3min^{-1}. Monitor the pressure levels and stop injection if the pressure at the final tapping point begins to rise.
14. Increase the temperature to 80°C, and leave shut in overnight.
15. Backflow with 10 PV of oil at 2 cm^3min^{-1} to return core to Swi. Measure the volume of the brine and emulsion (if any) phases, and take a sample of the brine phase for inhibitor concentration determination.
16. Measure the permeability to oil.
17. Backflow with 150 PV of brine at 2 cm^3min^{-1} and collect the effluent in suitably sized fractions. Measure the volume of oil eluted. Determine the inhibitor concentration in selected fractions to construct the desorption profile.
18. Measure the permeability to brine.
19. Backflow with 10 PV of oil at 2 cm^3min^{-1} to return core to S_{wi}.
20. Measure the permeability to oil.

The intermediate-wet tests differed from this routine by initially saturating the core with crude oil and then ageing it for 1 week at 80C. The oil was then displaced with Isopar, and the flood continued at step 6 in the water-wet sequence above.

During the overflush the intention was that the inhibitor slug would not reach the back end of the core, as maintaining oil continuity should prevent relative permeability end effects from influencing the pressure measurements recorded during the oil backflush after the inhibitor shut-in period.

For data presentation purposes the core plug was assigned a 'well bore' face and a 'formation' face. Oil was always flowed in the 'formation' to 'well bore' direction, whilst the inhibitor and overflush were injected in the 'well bore' to 'formation' direction.

4.2 Results from water-wet core

4.2.1 Inhibitor treatment influence on permeability

The permeability of individual sections along the core was measured at different stages of the core floods using the multiple pressure tappings. The oil permeabilities for the two experiments in water-wet core are shown in **Figure 9** and **Figure 10**, whilst brine permeabilities are plotted in **Figure 11** and **Figure 12**. The data are presented as the permeability in different sections of the core, with distance measured from the 'well bore' end.

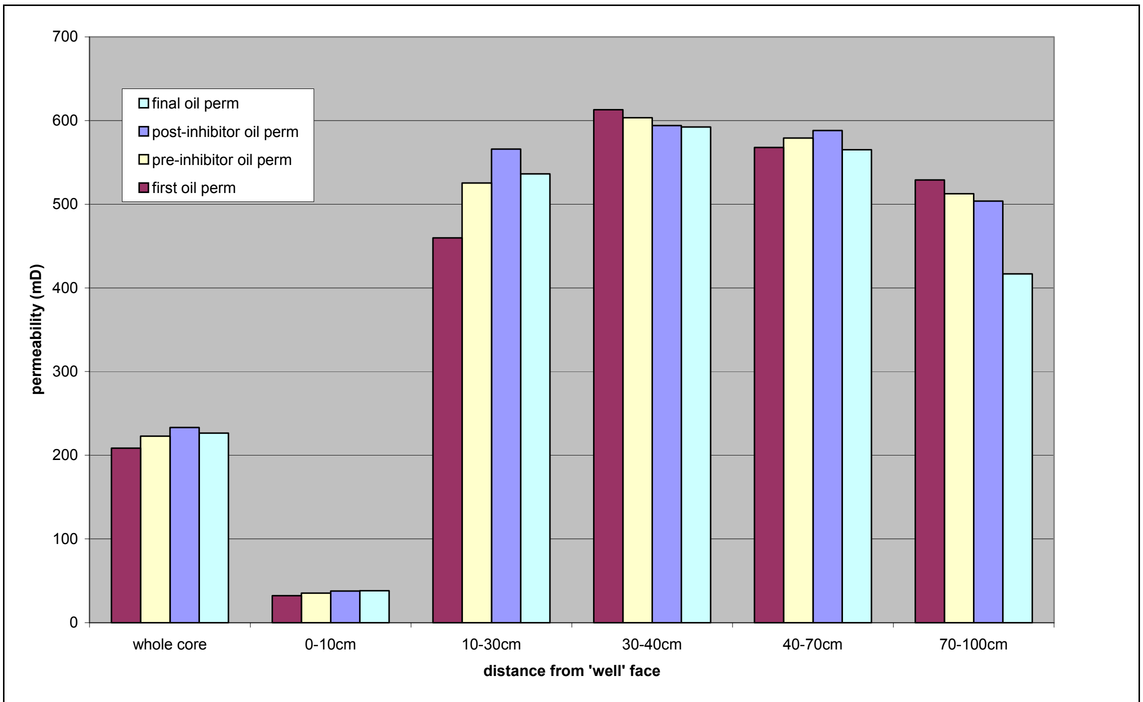

Figure 9. Oil permeabilities measured during the baseline flood

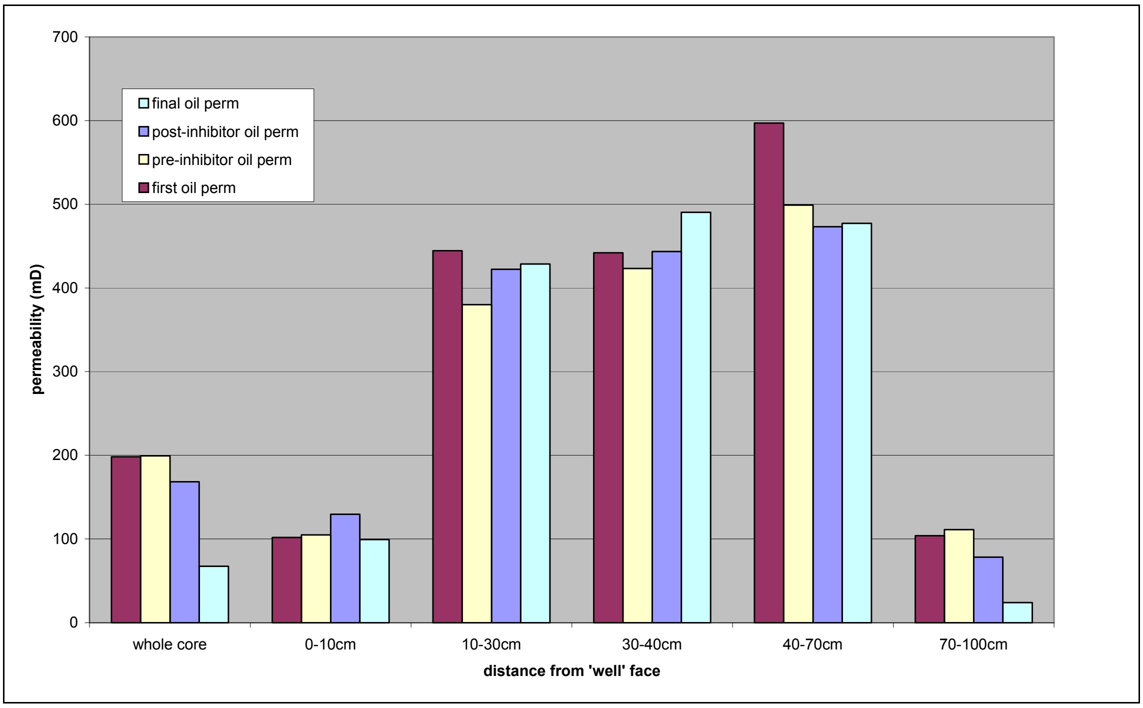

Figure 10. Oil permeabilities measured during the emulsion flood

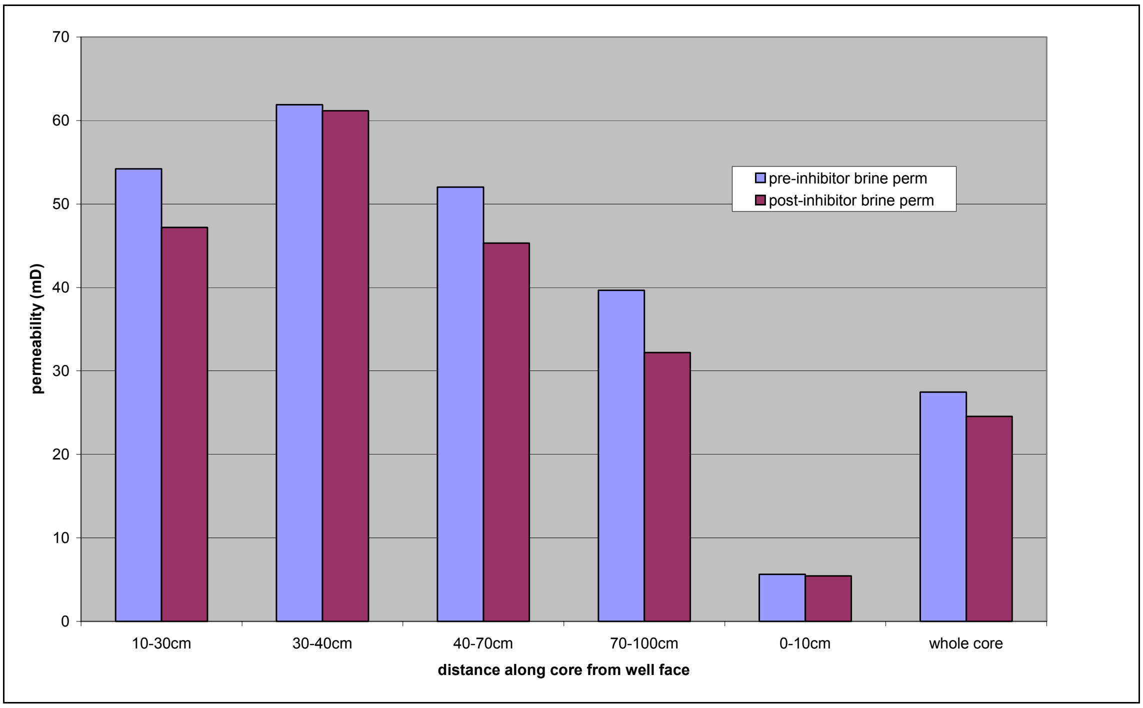

Figure 11. Brine permeabilities measured during the baseline flood

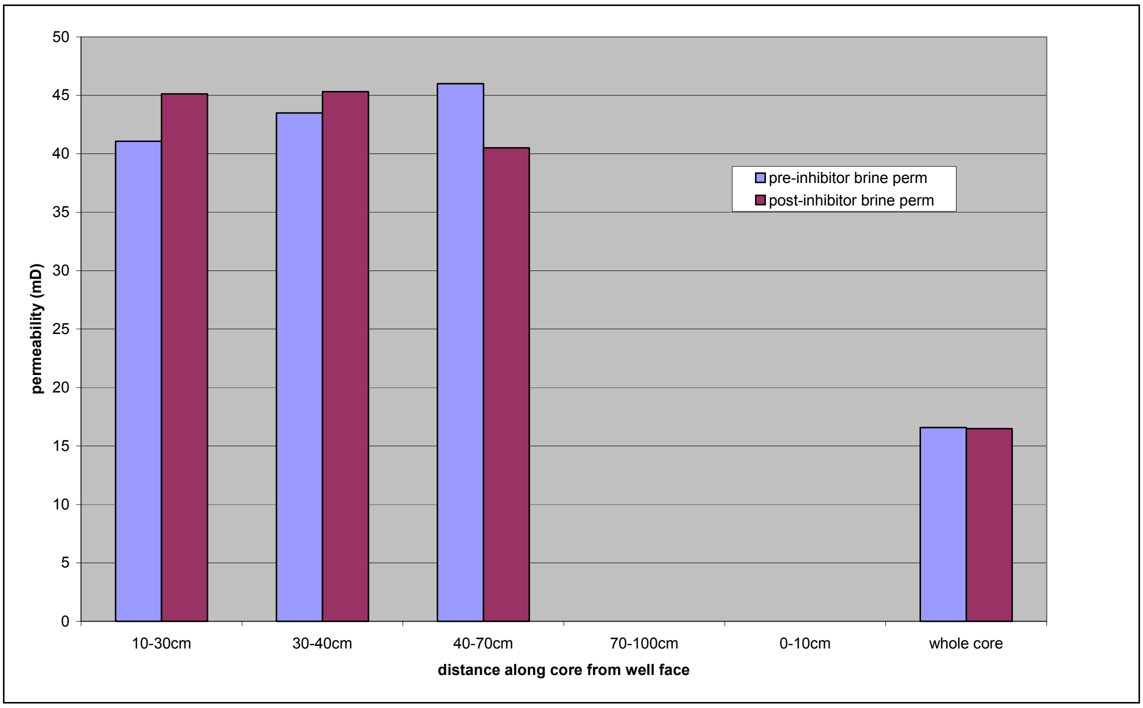

Figure 12. Brine permeabilities measured during the emulsion flood

The data show both cores had low permeabilities at the injection (‘wellbore’) face, giving overall initial oil relative permeabilities around 200 mD. Neither inhibitor treatment affected the core permeabilities, although the large brine postflush during which the inhibitor desorption profile was measured caused some permeability reduction in the emulsion flood. The slight reduction in overall permeability recorded is due to changes in the last 30 cm of the core, and the emulsion did not penetrate that far into it (see Figure 14). The permeability change is thought to be an artifact rather than an effect of the emulsion, due to particulates present in the brine.

The endpoint fluid saturations at each stage are shown in Figure 13, from which it can be seen that the only difference between the tests is that a lower brine saturation is recorded after the emulsion injection, as would be expected. The endpoint brine saturations were unchanged by either inhibitor treatment.

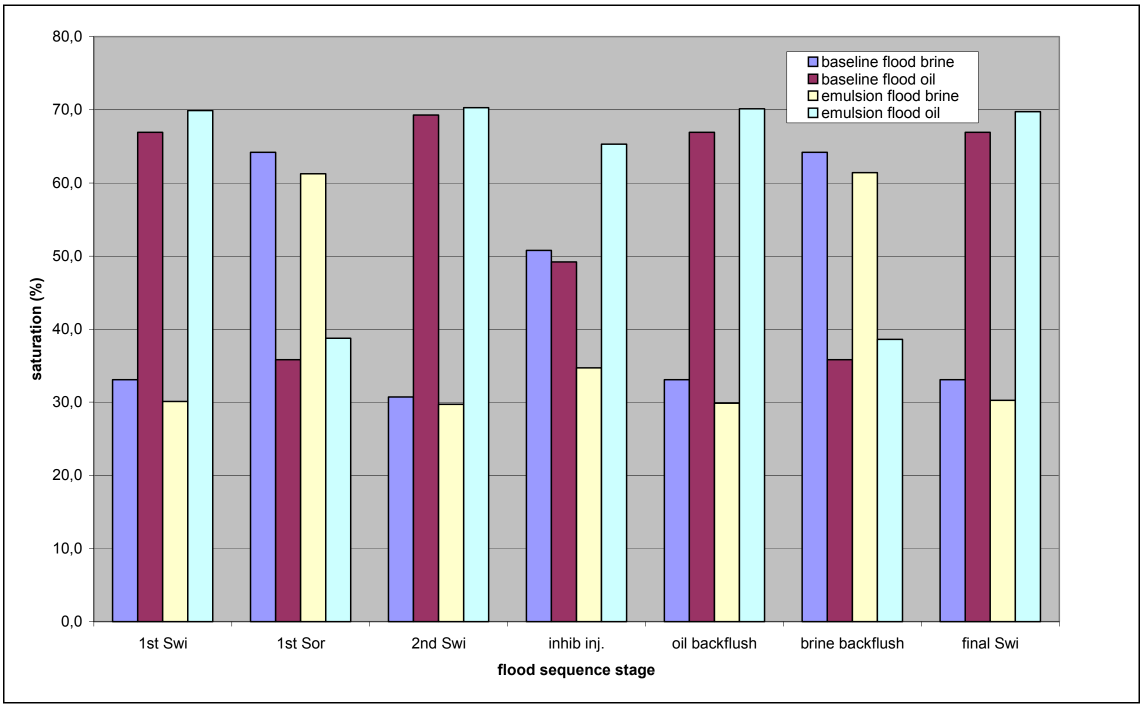

Figure 13. Endpoint fluid saturations during emulsion and baseline core floods

4.2.2 Inhibitor injection and overflush

Pressure data from the multiple tappings along the core permitted the progress of the inhibitor slug to be followed during injection and the subsequent oil overflush. The pressure distribution during the oil backflush after the shut-in period was also recorded.

A summary of the pressure drops recorded during emulsion injection, overflush, and the start of the post shut-in oil backflush in water-wet rock is shown in **Figure 14**, normalised for flow rate. A high pressure was recorded over the first 10 cm of core during emulsion injection (perhaps indicating some face blocking occurring), but the data show that as the emulsion slug is injected it penetrates more than 10 cm and less than 30 cm, as would be expected for 0.2 PV. The subsequent oil overflush quickly reduced the pressure in the first 10 cm, but appears to 'spread' the slug further into the core plug, rather than displace it as a unit. This is indicated by the sequential rise and fall of the pressure measured over 10 – 30 cm and 30 – 40 cm, and the final pressure rise in the 40 – 70 cm section. At the end of the overflush the same pressure is recorded between 10 and 70 cm into the core, suggesting that the viscosity is similar along that whole part of the core. The final transducer reading (70 – 100 cm) was unchanged throughout, and has been omitted from the plot to aid clarity.

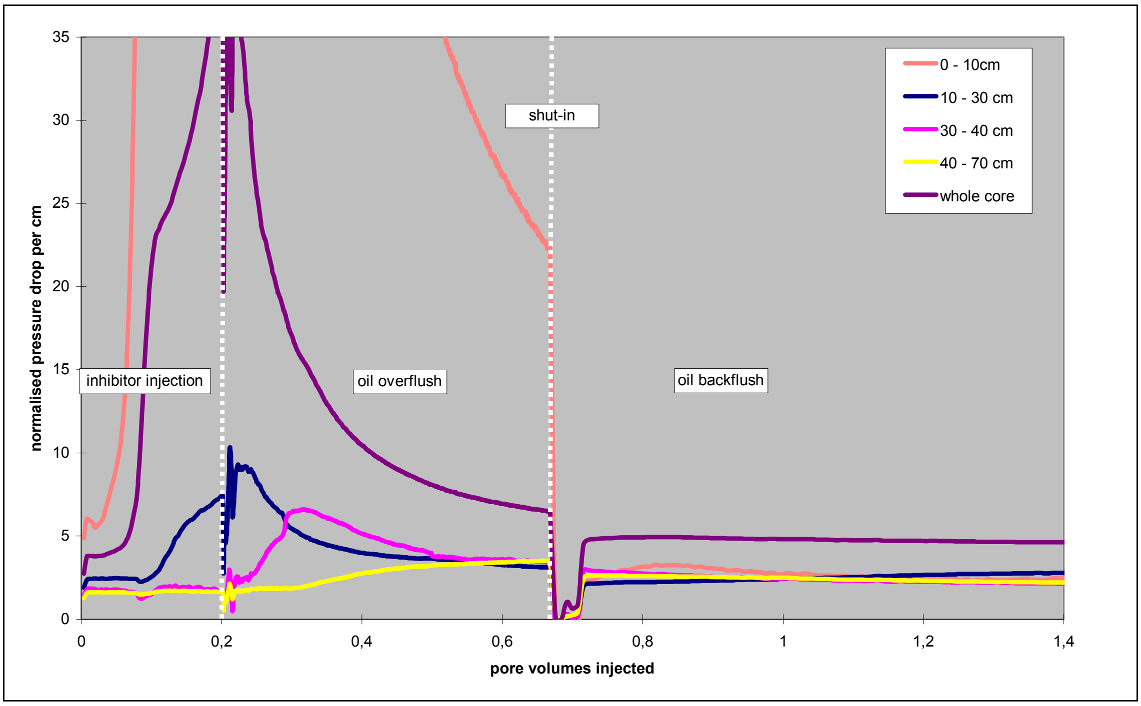

Figure 14. Summary of pressure drops during emulsion test in water-wet Berea

The pressure drops recorded during the oil backflush in the emulsion test show that the emulsion has broken during the shut-in, since pressure drop is lower than that observed during the emulsion overflush. The pressure drop across the whole core varies little during the flush, and there is no increased pressure requirement to instigate flow. However, there is a small higher viscosity 'slug' that is displaced from the final location of the emulsion after the overflush back towards, and out of, the 'well bore' face. This can be seen from the rise and fall of the 40-70, 30-40, and 10-30 cm pressure drops, and its elution from the core coincides with water being eluted. This occurred after about 0.7 pore volumes, and suggests that the majority of the emulsion droplets had been displaced into the core by the overflush. The volume of brine eluted coincided with the volume injected in the emulsion, indicating that the residual brine saturation level was unaffected by the emulsion.

The 0-10 cm pressure profile shows evidence of some outlet face blocking associated with the transport of material from the other end of the core, which is displaced out of the core after approximately 2 pore volumes of oil have been injected.

The pressure drops recorded during the baseline flood inhibitor slug injection, overflush, and the start of the backflush in water-wet rock are shown in **Figure 15**. The pressures recorded during inhibitor injection are twice as high as during the emulsion injection, and the inhibitor solution also penetrated further into the core plug (more than 40cm, compared with less than 30cm for the emulsion. The oil overflush was stopped after only 0.12 pore volumes (instead of 0.5 pore volumes) had been injected, as the inhibitor slug had reached the core outlet. This is indicated by the 70 – 100 cm pressure profile, and also brine droplets were observed in the core effluent.

The oil backflush after the inhibitor shut-in required significant pressure to start flow, and the displacement of the brine slug back through the core can be followed in the sequential pressure profile rise and fall (**Figure 15**). Since the inhibitor slug reached the core outlet during injection it may be that some of the observed initial pressure rise is due to end effects, but the high pressures recorded as the brine progresses through the core indicate that significantly more pressure is required to move the brine slug compared to the broken emulsion in the previous test (compare **Figure 14** with **Figure 15**).

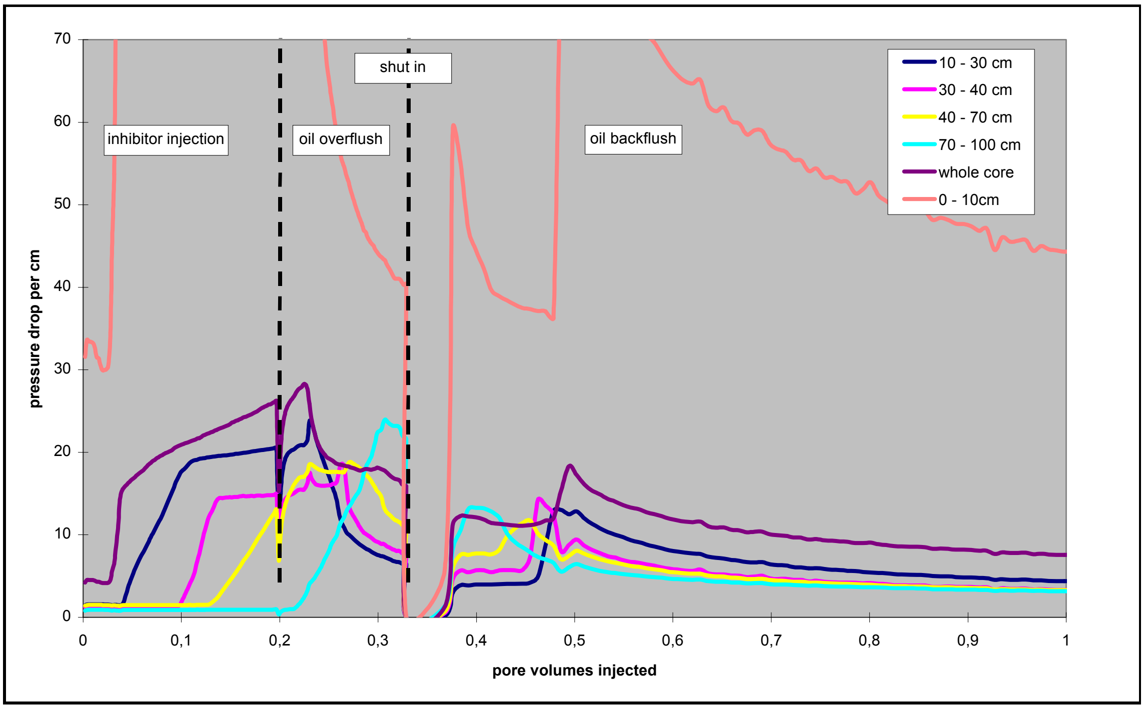

Figure 15. Summary of pressure drops during baseline test in water-wet core

4.3 Results from intermediate-wet core

4.3.1 Inhibitor treatment influence on permeability

The oil relative permeabilities measured over individual sections of the core at selected stages of the emulsion test are shown in Figure 16, whilst the brine permeabilities at residual oil are shown in Figure 17. The permeability values measured during the baseline seawater inhibitor solution injection are shown in Figure 18 and Figure 19. From the data it can be seen that overall the oil permeability of the core is little changed, whilst the brine permeability is significantly reduced. The changes recorded in individual sections along the core indicate a wetability change back towards water wet has occurred, since both the increase in oil permeability and decrease in brine permeability reduce in size with distance into the core. The change was probably induced by the inhibitor, since it greatest at the front of the core; this effect was also observed in the tests investigating the effect of wetability of inhibitor desorption profiles reported previously. Both permeabilities were reduced in the 70-100 cm section, but this is probably (at least in part) an artifact due to the large volume of brine injected during the backflush. The appearance of the core face on removal after the test indicated some face blocking may have occurred due to fine material suspended in the brine even though it was filtered to 0.45 μm before injection. The low permeability of the first 10 cm of the core is due to the presence of clay bands which run perpendicular to the core axis in that section.

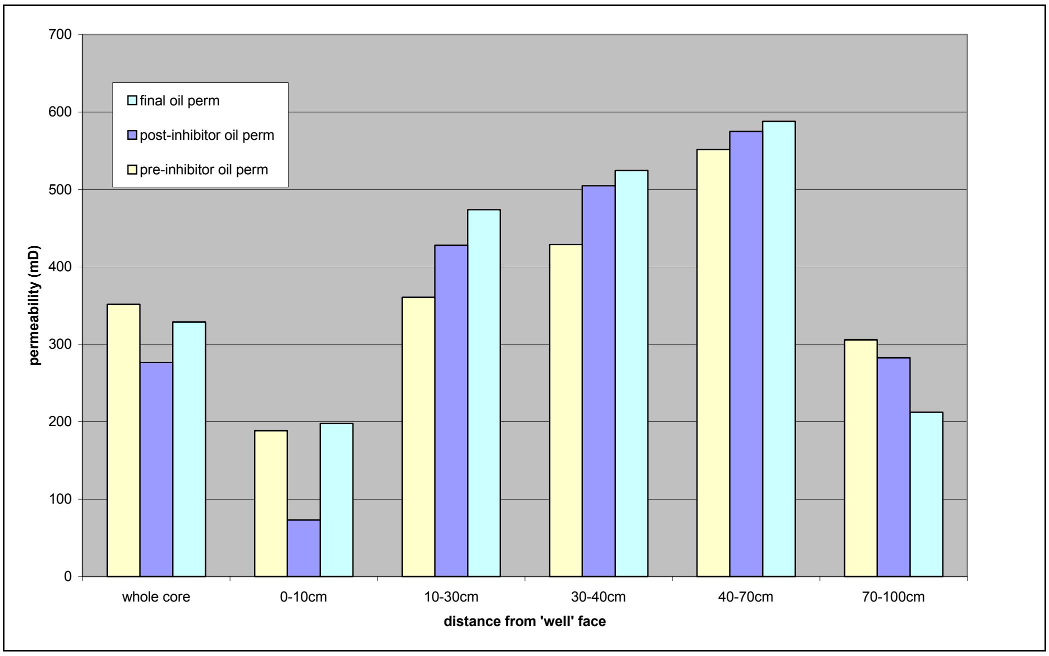

Figure 16. Oil permeabilites at residual brine in individual sections (emulsion test, intermediate wet core)

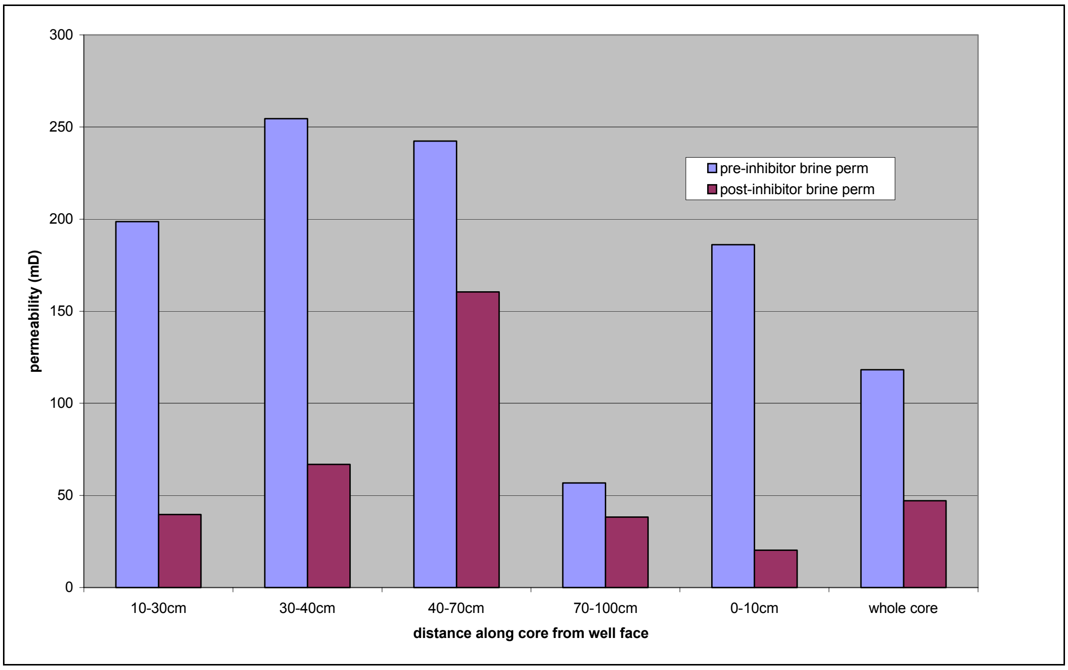

Figure 17. Brine permeabilites at residual oil in individual sections (emulsion test, intermediate wet core)

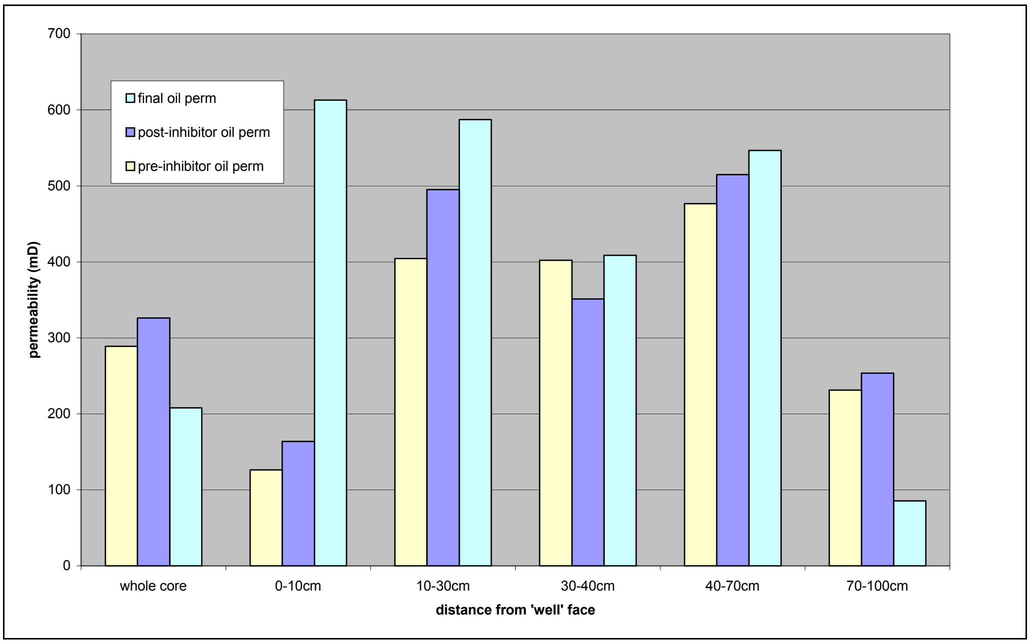

Figure 18. Oil permeabilities at residual brine in individual core sections (seawater solution, intermediate wet core)

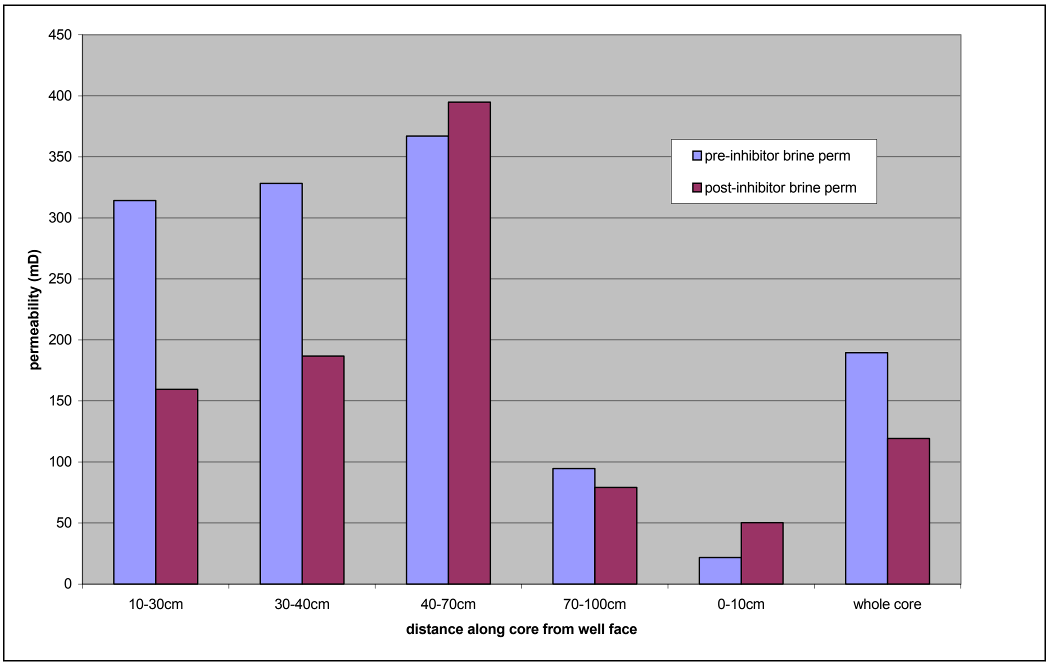

Figure 19. Brine permeabilities at residual oil in individual core sections (seawater solution test intermediate wet core)

4.3.2 Inhibitor injection and overflush

The pressure drop during emulsion injection, overflush, and oil backflush after shut-in is shown in Figure 20, whilst the data for the seawater baseline test is plotted in Figure 21. Both inhibitor systems showed similar behaviour and recorded pressures during injection to the previous tests in water-wet core, although the pressures during the overflush indicate that the integrity of the emulsion slug is better maintained than in the water-wet test. After the shut in the broken emulsion was easily displaced back through the core, as the low recorded pressures indicate. The seawater inhibitor solution also behaved in a similar way to the water-wet test, and the progress of both inhibitor slugs through the core plugs may be followed by the sequential rise and fall of the pressure in individual core sections.

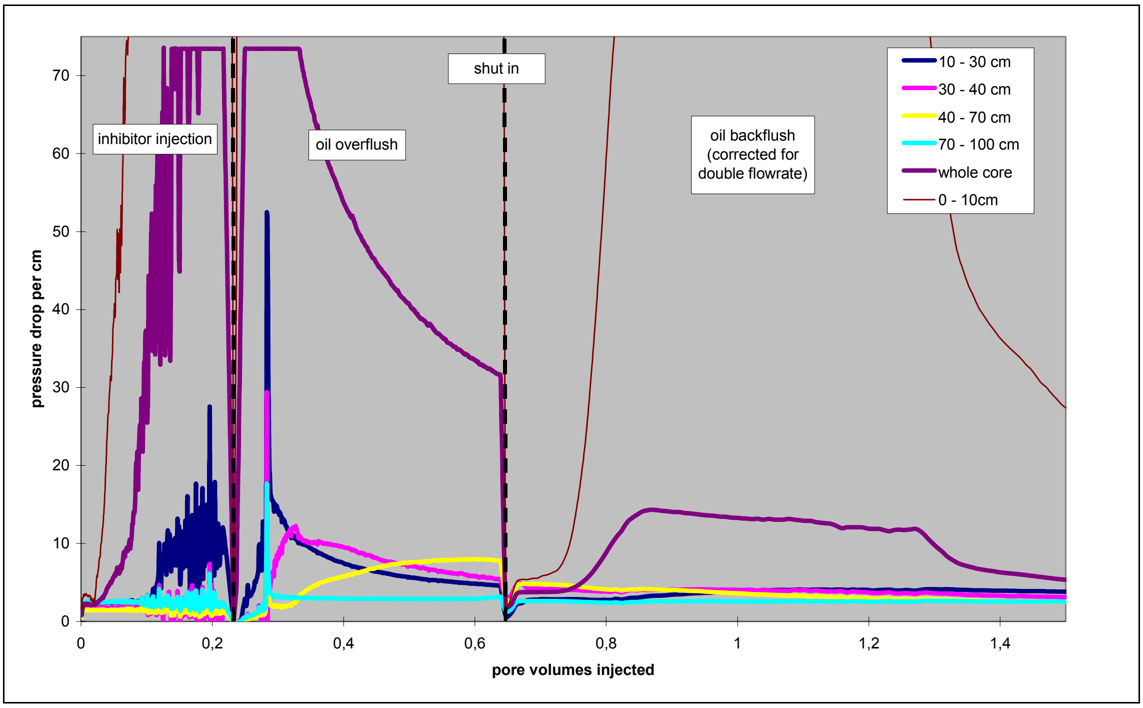

Figure 20. Pressure drops during emulsion injection, overflush, and displacement after shut in (intermediate-wet core)

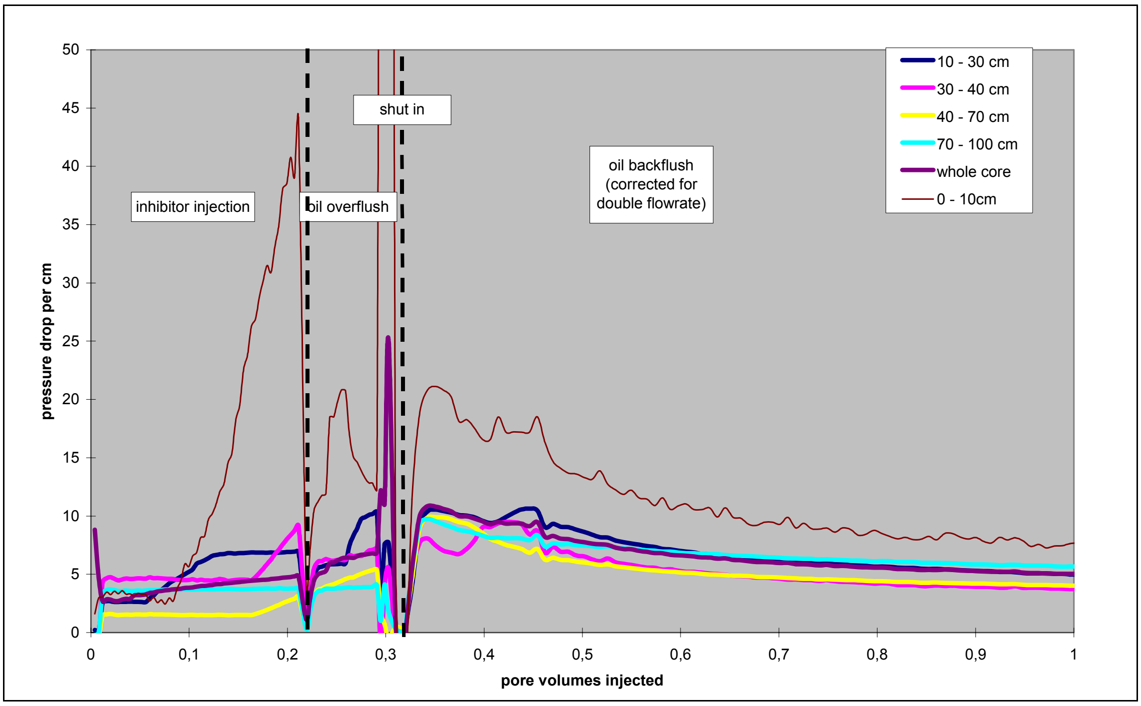

Figure 21. Pressure drops during seawater inhibitor solution injection, overflush, and displacement after shut in (intermediate-wet core)

4.4 Inhibitor desorption

The inhibitor desorption profiles in all the corefloods were measured over a 150 pore volume backflush, and the results are plotted in **Figure 22**. The data indicate similar inhibitor return from all tests except the seawater solution in water-wet core. The results show that there is little difference between seawater inhibitor solution and the emulsified system, and the core wetability also has little effect.

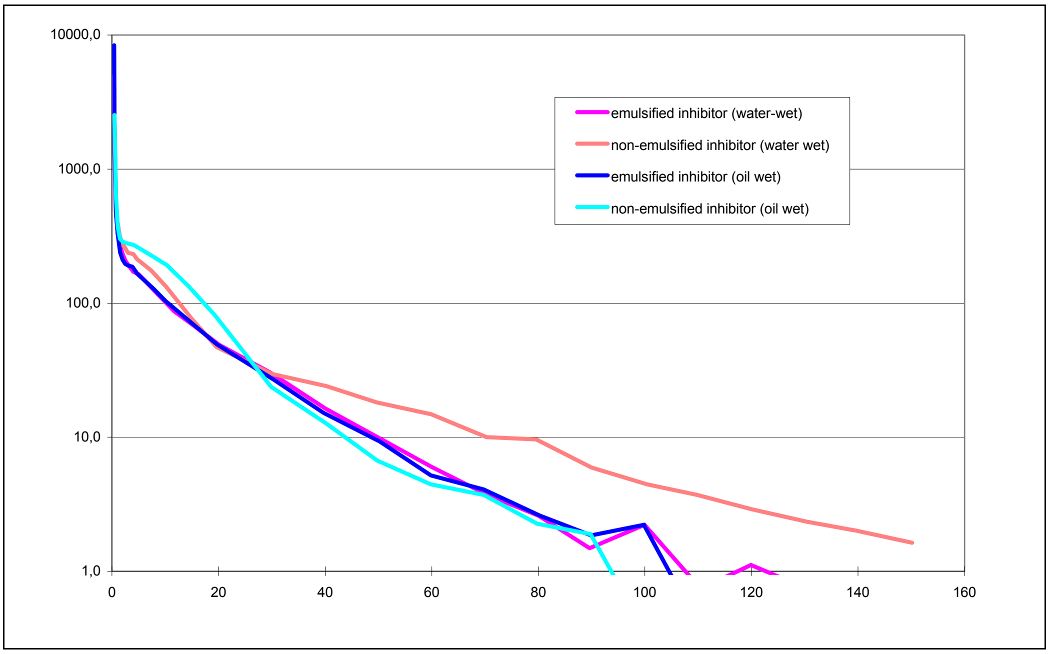

Figure 22. Inhibitor desorption profiles

4.5 Discussion

The three objectives of these tests were: (1) to examine whether the emulsion can be efficiently displaced into the rock with an oil overflush, (2) to compare the displacement of emulsion with that of a seawater slug, and (3) to further confirm the advantages of the emulsion with regard to re-start pressure after shut-in.
The data confirm that a lower pressure is required to re-start oil flow after an emulsion treatment when compared to restoring the rock to residual brine after a 'normal' brine inhibitor solution injection. In all tests the pressure profiles from the individual tapping points show the zone of increased brine saturation being displaced back through the core by the oil backflush, but the effect on the pressure is much greater in the brine treatment. The benefits of the emulsion system in this respect are therefore clear.

The pressure data also show that the emulsion behaves differently to the brine inhibitor solution during injection and overflush, and also that the behavioural differences are independent of wetability. The emulsion invades approximately its own volume of rock (0.2 PV goes less than 30 cm into the 1 metre core), and is displaced at most a further 50 cm by a 0.5 PV overflush. This suggests that almost all of the pore volume is available to the emulsion, even though the core is at residual brine when injection begins. Compare that to the brine inhibitor solution injection, in which injecting 0.2 PV caused the pressure to increase up to between 40 and 70 cm into the core. This agrees with the expected penetration, since from the residual fluid saturations an additional 35% of the pore space is available to injected brine when the core is at S_{wi}. This translates to a penetration of 71cm for a 0.2 PV brine slug, which is in good agreement with the experimental observation. This leaves only about 0.1 PV for the oil overflush to displace before breakthrough occurs, which the data show is what happened.

The actual inhibitor slug probably only penetrated about 30 cm into the core before the overflush was done, with the increased pressure observed deeper in the core being generated by the displaced residual brine front. However, the oil overflush would have fingered through the inhibitor slug generating some two-phase flow and taking some of the inhibitor solution with it, which coupled with diffusion during the shut-in period may have spread the inhibitor throughout the core. This contrasts with the emulsion situation, in which the inhibitor only spread three-quarters of the way into the core, with the final 25% of the core still more or less at residual brine. Assuming that in both cases the inhibitor concentration in the brine remains above the amount required for maximum adsorption, this would result in greater retention from the brine slug than the emulsion. This theory also potentially explains the inhibitor desorption profile (**Figure 22**) in which the baseline test in water-wet rock had a longer desorption life. However, for the intermediate-wet rock, which is probably more representative of the field situation, there was no difference between the different inhibitor systems.

5 Conclusions

The work performed this year has served both to further confirm the potential benefits of emulsion systems, and also to investigate field application feasibility. The data obtained shows that:

Emulsion systems are easier to inject into oil-wet than water-wet rock. Emulsions with 50:50 oil:water ratios may be injected into rock with permeability as low as 100 mD, although injection pressures are higher than would be expected from the fluid viscosity alone. This is probably due to the internal phase droplets deforming as they pass through the pores, and/or the build up and break down of droplet bridges at pore throats.

The emulsion may be displaced easily through the formation by an oil overflush, although in water-wet rock the emulsion tends to spread out through the rock rather than be displaced as a slug as happens in oil-wet rock.

The rock wetability does not influence the inhibitor desorption characteristics from an overflushed emulsion slug, although if the slug is not displaced into the core the inhibitor release profile is slightly lowered by altering the wetability towards oil-wetting. Overflushed treatments in intermediate-wet rock show no difference in inhibitor release profiles between emulsions and seawater solution of inhibitor.

The emulsion systems has been developed and qualified to a stage where the next step is optimisation for application to a specific well, so that it may be field trialled.

Appendix 1. Field-specific test protocol

The emulsion system developed in the project was not targeted towards a specific field, but was developed by generic testing. Before the system may be applied to a specific well, it should be optimised for the intended application. To this end, the following laboratory work is recommended.

Bulk tests: Emulsion generation and breaking characteristics

Tests should be performed to establish whether the field scale inhibitor and seawater can be emulsified at an appropriate concentration to produce the desired inhibitor concentration when the emulsion breaks downhole.

The surfactant concentrations and/or types may have to be adjusted to obtain emulsion breaking at the field downhole temperature, whilst still maintaining its integrity at the proposed treatment injection temperature. A series of breaking tests should also be performed to establish the influence on the emulsion breaking characteristics (if any) of mixing the emulsion with reservoir produced water and crude oil.

Core flood tests: Emulsion injection and formation damage potential, inhibitor desorption profile.

A carefully designed core flooding procedure could address all the required aspects of emulsion performance in a single test. However, duplicate tests should be perform to give confidence in the data obtained. Only the reservoir specific aspect of treatment application need be address in the optimisation process. The requirement for reduced drawdown to restart oil production and the displacement of the emulsion into the formation by oil overflush have been demonstrated generically in this project and would not need confirming in reservoir-specific tests. The core flood test would comprise the following stages, utilising native state reservoir core and field brines and crude oil.

1. Condition the core to residual brine, measuring end-state relative permeabilities.
2. Cool the core to the injection temperature. Inject 5 pore volumes of emulsion whilst constantly monitoring the pressure drop across the core plug.
3. Shut in and increase the temperature to the reservoir temperature. Leave the core shut in to allow the emulsion to break.
4. Backflow the core with oil until steady-state pressure drop is obtained, then measure the permeability to oil.
5. Backflow with sufficient brine to construct the inhibitor desorption profile (probably 500 pore volumes).
6. Measure the permeability to brine.
7. Flush with oil to obtain residual brine and measure the final permeability to oil.

Step 2 gives an indication of emulsion injectivity, in terms of both injection pressure and also whether steady-state injection conditions may be obtained. A build up of emulsion leading to inlet face blocking which would lead to poor performance in the field would be observed at this stage.

A comparison core flood would also need to be performed using the same flood routine with the usual field scale inhibitor treatment replacing the emulsion system. Comparison of the two tests would permit identification of likely emulsion benefits in terms of reduced formation damage in sensitive reservoirs, and also indicate whether treatment lifetime will be affected (either positively or negatively) by using an emulsion system.

Appendix 2. Considerations for field application of an emulsified scale inhibitor

The use of an emulsified inhibitor system will necessarily incur greater costs than a convention squeeze treatment, and so its benefits must justify the financial commitment. Emulsified systems have specific applications where they may provide sufficient benefit to justify their use. The benefits obtained from the emulsion are:

- Reduced drawdown required to re-start production
- Reduced volume of water injected
- Reduced deferred oil
- Potentially longer squeeze life

For water-sensitive or low pressure formations emulsions may be an economically viable squeeze treatment, even if enhanced squeeze life-time is not obtained.

However, for a treatment to be successful, it must be possible to:

- Generate an emulsion which breaks at the reservoir temperature
- Cool the reservoir sufficiently by pre-flushing to inject the emulsion below its breaking temperature

And the formation to be treated must:

- Have sufficiently large pore size (permeability) to permit injection of the emulsion without droplets blocking or bridging pores
- Have a sufficiently high fracture pressure to permit emulsion injection at a suitable rate

It is not possible to set limiting values for these parameters, since there is a complex interrelationship between parameters such as emulsion O:W ratio, injection pressure, permeability, pore size, wetability, and temperature. The simplest way to evaluate a particular application is by field-specific laboratory tests. The test routines required are simple to perform, and are outlined in Appendix 1.